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

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2014

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 ☒ No ☐

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

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

Indicate by check mark whether the registrant has submitted electronically 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 ☒ 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 ☒ 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	☒		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 ☒

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, 2014): $6,213,156,302.

At January 31, 2015, there were 175,549,934 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 2015 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 1-800-SEC-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 the Company's 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: 1-303-672-6900).

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:

- impact of the sale of QEP Field Services Company's midstream business;
- ability to deliver continued growth by focusing on exploration and production assets;
- compliance with governmental regulations;
- risks associated with hydraulic fracturing;
- maintaining leasehold inventory by drilling;
- adequacy of insurance;
- timing and impact of proposed environmental legislation and studies;
- strong liquidity position providing financial flexibility;
- adequacy of the Company's production and reserves to meet term sales commitments;
- ability to purchase gas to satisfy delivery commitments;
- ability to pursue acquisition opportunities;
- fair value and critical accounting estimates;
- plans to recover or reject ethane from produced natural gas;
- QEP’s growth strategies;
- impact of lower or higher commodity prices and interest rates;
- impact of global geopolitical and macroeconomic events;
- plans to enter into derivative contracts and managing counterparty risk;
- plans to drill or participate in wells;
- results from planned drilling operations and production operations;
- pro forma results for acquired properties;
- the Company's liquidity and sufficiency of cash flow from operations, cash-on-hand and availability under its credit facility to fund the Company's planned capital expenditures and operating expenses;
- plans to divest of non-core assets;
- expected gain or loss on sale of assets;
- factors impacting oil, gas and NGL prices;
- seasonality of QEP's operating results;

- assumptions regarding equity compensation;
- ability to realize income tax benefits;
- recognition of compensation costs related to equity compensation grants;
- obligations under drilling contracts;
- amount and allocation of forecasted capital expenditures and plans for funding capital expenditures and operating expenses;
- the outcome of contingencies such as legal proceedings;
- estimated accrual for loss contingencies and other items and likelihood that indemnification obligations will be satisfied;
- financial impact of operational hazards;
- future expenses and operating costs;
- the amount, type and timing of derivative contracts and unrealized derivative gains and losses;
- impact of nonperformance by trade creditors or joint venture partners;
- adequacy of credit review procedures, loss reserves, customer deposits and collection procedures to protect against credit related issues;
- the Company's credit rating;
- loss of any large customer and the ability of the Company to replace customers;
- expected contributions to the Company's pension plans and returns from plan assets;
- expected savings from service providers;
- the importance of Adjusted EBITDA (a non-GAAP financial measure) as a measure of performance;
- delays caused by transportation and refining capacity issues;
- payment of dividends;
- considerations regarding the standardized measure of future net cash flows relating to proved reserves;
- potential for future asset impairments and impact of impairments on financial statements; and
- factors impacting the timing and amount of share repurchases.

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 discussed in Part I, Item 1A of this Annual Report on Form 10-K;
- changes in gas, oil and NGL prices;
- general economic conditions, including the performance of financial markets and interest rates;
- drilling results;
- shortages of oilfield equipment, services and personnel;
- lack of available pipeline, processing and refining capacity;
- QEP's ability to successfully integrate acquired assets or divest of non-core assets;
- the outcome of contingencies such as legal proceedings;
- permitting delays;
- operating risks such as unexpected drilling conditions;
- weather conditions;
- the availability and cost of debt and equity financing;
- changes in laws or regulations;
- legislation regarding climate change and other initiatives related to drilling and completion techniques, including hydraulic fracturing;
- derivative activities;
- volatility in the commodity-futures market;
- substantial liabilities from legal proceedings and environmental claims;
- failure of internal controls and procedures;
- failure of QEP's information technology infrastructure or applications;
- elimination of federal income tax deductions for oil and gas exploration and development costs;
- regulatory approvals and compliance with contractual obligations;
- actions, or inaction, by federal, state, local or tribal governments;
- lack of, or disruptions in, adequate and reliable transportation for QEP's production;
- competitive conditions;
- production levels;

- reserve levels; 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. 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.

cryogenic processing Natural gas processing method to extract NGL from natural gas by reducing the gas temperature to 100 degrees below zero Fahrenheit.

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.

LLS The price of Louisiana Light Sweet crude oil on the New York Mercantile Exchange.

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 determined by the sum of the fractional ownership interest the Company has in the gross wells or acres.

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).

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 2014
PART I

ITEM 1. BUSINESS

Nature of Business

QEP Resources, Inc. (QEP or the Company) is a holding company with two 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 the Haynesville Gathering System and an underground gas storage facility (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.

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.

Reincorporation Merger and Spin-off from Questar

Effective May 18, 2010, Questar Market Resources Inc. (Market Resources), then a wholly owned, public subsidiary of Questar Corporation (Questar), merged with and into a newly formed, wholly owned subsidiary, QEP Resources, Inc., a Delaware corporation, in order to reincorporate in the State of Delaware (the Reincorporation Merger). The Reincorporation Merger was effected pursuant to an Agreement and Plan of Merger entered into between Market Resources and QEP. On June 30, 2010, Questar distributed all of the shares of common stock of QEP held by Questar to Questar shareholders in a tax-free, pro rata dividend (the Spin-off). Each Questar shareholder received one share of QEP common stock for each share of Questar common stock held at the close of business on the record date. In connection with the Spin-off, QEP distributed Wexpro Company (Wexpro), a wholly owned subsidiary of QEP at the time, to Questar. In addition, Questar contributed $250.0 million of equity to QEP prior to the Spin-off.

Discontinued Operations

In October 2014, the Company announced that its wholly owned subsidiary, QEP Field Services Company (QEP Field Services), had entered into a definitive agreement to sell substantially all of its midstream business, including the Company's ownership interest in QEP Midstream Partners, LP (QEP Midstream), to Tesoro Logistics LP (Tesoro). On December 2, 2014, QEP closed the sale of its midstream business to Tesoro (Midstream Sale) for total cash proceeds of $2.5 billion, including $230.0 million to refinance debt at QEP Midstream, subject to post-closing adjustments, and QEP recorded a pre-tax gain of $1.8 billion on its Consolidated Statements of Operations in "Net income from discontinued operations, net of income tax" for the year ended December 31, 2014. The decision to sell the midstream business was the result of the Company’s ongoing review of strategic alternatives to maximize shareholder value. QEP Marketing retained ownership of the Haynesville Gathering System. As a result of the Midstream Sale, the QEP Field Services reporting segment, excluding the retained ownership of the Haynesville Gathering System, has been classified as a discontinued operation on the Consolidated Statement of Operations and the Notes accompanying the Consolidated Financial Statements. For reporting purposes, the retained Haynesville Gathering System has been combined with QEP Marketing and Other.

Financial and Operating Highlights

Our financial and operating highlights for 2014 are as follows:

- Incurred a net loss from continuing operations of $409.5 million, or $2.28 per diluted share, a decrease of $461.6 million from the net income from continuing operations of $52.1 million, or $0.29 per diluted share, in 2013;
- Generated Adjusted EBITDA from continuing operations (a non-GAAP financial measure defined and reconciled in Item 7 of Part II of this Annual Report on Form 10-K) of $1,438.3 million, up from $1,316.0 million in 2013;
- Increased liquids (oil and NGL) production by 59% to 143.4 Bcfe;
- Increased liquid (oil and NGL) proved reserves by 7% to 1.6 Tcfe;
- Added 294.1 Bcfe of proved reserves from extensions and discoveries;
- Completed the Midstream Sale for approximately $2.5 billion, including $230.0 million to refinance debt at QEP Midstream, resulting in a pre-tax gain on sale of approximately $1.8 billion;
- Completed the acquisition of oil and gas properties in the Permian Basin of Texas for an aggregate purchase price of $941.8 million; and

- Completed sales of non-core oil and gas properties for aggregate proceeds of $787.8 million, resulting in a pre-tax loss of $146.1 million.

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;
- be in 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 fluctuating interest rates, while locking 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.

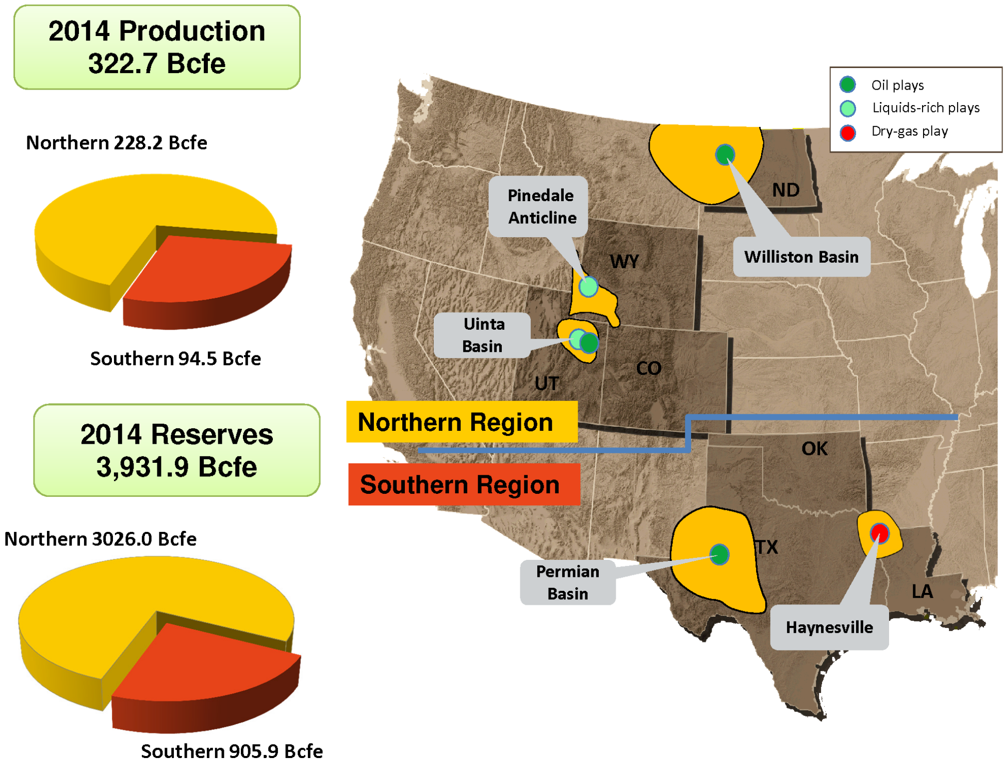
On December 2, 2014, QEP completed the Midstream Sale; see "Discontinued Operations" above. QEP believes this decision represents a significant milestone in the strategic repositioning of the Company, as it will be better positioned to deliver continued growth by focusing on its exploration and production 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, primarily 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. During 2013 and 2014, QEP sold the majority of its former properties within its Midcontinent area 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 consist 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 creates a new core area of operation for QEP Energy. Additionally, during the third quarter of 2012, QEP Energy acquired oil and gas properties in the Williston Basin for an aggregate purchase price of $1.4 billion (the Williston Basin Acquisition).

The following map illustrates the location of the Company's significant E&P activities, its Northern and Southern Regions described elsewhere in this report, and related reserve and production data as of December 31, 2014:



QEP Energy generated approximately $1,437.0 million, $1,301.8 million, and $1,118.4 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) during the years ended December 31, 2014, 2013 and 2012, respectively. During 2014, QEP Energy operated in two core 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 71% of 2014 production, while the Southern Region contributed 29%. QEP Energy reported 3,931.9 Bcfe of estimated proved reserves as of December 31, 2014, down 130.0 Bcfe from 2013. Of those estimated proved reserves, approximately 77%, or 3,026.0 Bcfe, were located in the Northern Region at December 31, 2014, compared to 75%, or 3,039.7 Bcfe, at December 31, 2013. The remaining 23%, or 905.9 Bcfe, were located in the Southern Region at December 31, 2014, compared to 25%, or 1,022.2 Bcfe, at December 31, 2013. Approximately 56% of the total proved reserves reported by QEP Energy at December 31, 2014, were developed and approximately 41% of the total proved reserves were comprised of oil and NGL, up from 37% at December 31, 2013.

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 has lower risk than 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 large numbers of complex, highly deviated or horizontal wells to vertical depths that 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. QEP Energy also conducts some exploratory drilling to determine the commercial viability of its unproven leasehold inventory. For 2015, QEP plans to allocate approximately $960.0 million of its capital budget to E&P activities. QEP Energy seeks to maintain geographical and geological diversity with its two core regions. In addition to the Williston Basin Acquisition in 2012 and the Permian Basin Acquisition in 2014, 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, both directly and through its affiliate, QEP Marketing, 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 $1.3 million, $14.2 million and $39.0 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, 2014, 2013 and 2012, respectively. As a wholesale marketing entity, QEP Marketing concentrates on markets in the Rocky Mountains and Midcontinent 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 sells NGL volumes associated with the gas stored in its Clear Creek storage facility. In addition, QEP Marketing owns and operates the Haynesville Gathering System, located in Louisiana. The Haynesville Gathering System 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 QEP Energy's gas and volumes purchased from third parties to wholesale marketers, industrial end-users and utilities. QEP Marketing sells QEP Energy's oil volume 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 regulation under a wide range of local, state, tribal and federal statutes, rules, orders and regulations. The regulatory burden on the oil and gas industry increases the cost of doing business and consequently affects its 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 complex federal, state, tribal and local regulations that may affect the Company, 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 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.

Greenhouse Gases Regulations and Climate Change Legislation. The Environmental Protection Agency (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 adopted regulations for the measurement and reporting of GHG emitted from certain large facilities. In November 2010, the EPA expanded its GHG Reporting Rule to include onshore oil and gas production, processing, transmission, storage, and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis. 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, legal measures to reduce emissions of GHG, primarily through the development of GHG inventories, GHG permitting and/or regional GHG cap and trade programs; however, some states have required or proposed direct regulation of GHG emissions from oil and gas facilities, including, for example, methane leak detection monitoring and repair for upstream oil and gas activities and best management practices for well liquids unloading activities.

The EPA is also considering direct regulation of methane emissions from oil and gas facilities. On January 14, 2015, the White House and the U.S. Environmental Protection Agency indicated that they plan to amend 40 C.F.R Part 60, Subpart OOOO (Subpart OOOO) standards to achieve additional methane and volatile organic compound reductions from the oil and natural gas industry. These potential amendments to Subpart OOOO could result in additional regulatory requirements and standards for completions of hydraulically fractured oil wells, pneumatic pumps, and leaks from new and modified oil and gas exploration, production, and gathering facilities. A proposed rule is expected in 2015, with a final rule expected in 2016.

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 U.S. (e.g., lakes, rivers, wetlands, and streams) as well as discharges to storm water. 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 or release of water produced or used during oil and gas development.

Oil Pollution Act of 1990. The Oil Pollution Act of 1990 (OPA) and regulations issued under OPA impose strict, joint and several liability on "responsible parties" for removal costs and damages 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 that contributed to the release of a "hazardous substance" 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 and liability for failure to meet such 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 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 and shale reservoirs require hydraulic fracture stimulation to achieve economic production rates and recoverable reserves. The majority of the Company'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 comprised 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. The Company does not use diesel fuel in any of its fracturing operations. The Company 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).

The Company obtains water for fracture stimulations from a variety of sources, including industrial water wells and surface water sources. When technically and economically feasible, the Company 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 to protect water quality such as conducting baseline sampling for all new water wells, 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. The Company believes that the employment of fracture stimulation technology does not present any significant additional risks other than the risks 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 and operation. Additionally, in May 2012 the Bureau of Land Management (BLM) proposed new regulations regarding chemical disclosure requirements and other regulations specific to well stimulation activities, including hydraulic fracturing, on federal and tribal land, and proposed revisions to those regulations in May 2013. Those proposed regulations are still pending with the BLM and are not final. There has been a heightened debate recently over whether the fluids used in hydraulic fracturing may contaminate drinking water supplies, and proposals have been made to revisit the permitting exemption for hydraulic fracturing under the SDWA or to enact separate federal legislation or legislation at the state and local government levels that would regulate hydraulic fracturing.

The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices and a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with final results expected to be available in 2015. Moreover, the EPA announced in October 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and plans to propose standards that such wastewater must meet before being transported to a publicly owned treatment plant. 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. In addition, the Department of Energy is conducting an investigation of practices the agency could recommend to better protect the environment from drilling employing hydraulic fracture stimulation.

Additionally, a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices, and recent Congressional legislative efforts seek to regulate hydraulic fracturing under the SDWA's Underground Injection Control program, which would significantly increase well capital costs. Certain members of Congress have also called upon (1) the Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources; (2) the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing; and (3) the Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. Additionally, federal and state agencies are studying air quality impacts from hydraulic fracturing practices. These ongoing or proposed studies and investigations could spur initiatives to further regulate hydraulic fracturing under the SDWA, the Clean Air Act or other statutes and regulatory programs.

Tribal Lands and Minerals. Various federal agencies within the U.S. Department of the Interior, particularly the BLM and the Bureau of Indian Affairs, 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 such matters as lease provisions, drilling and production requirements, environmental standards and royalty considerations.

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 facilities to disseminate information on chemical inventories to employees as well as local emergency planning committees and emergency response departments. On January 7, 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 EPCRA's Toxics Release Inventory (TRI) program. 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.

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.

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, 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.

Other Regulations. The U.S. Department of Transportation has started rulemaking to develop new requirements for shipping crude oil by rail.

State Regulations

North Dakota. The North Dakota Industrial Commission (the Commission), North Dakota's chief energy regulator, recently issued an order to reduce the volume of natural gas flared from oil wells in the Bakken and Three Forks formations. In addition, the Commission is requiring 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 the Company’s production forecasts and midstream agreements, QEP believes it is and will continue to be in compliance with this new 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 improve the marketability and safe transportation of the crude oil. The Commission's order is effective April 1, 2015. QEP believes it is currently in compliance with this new order from the Commission.

Regulation of Underground Storage

QEP, through its wholly owned subsidiary Clear Creek Storage Company, LLC, 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.

Seasonality

QEP's results of operations can be negatively impacted by the weather. In the Pinedale field, QEP typically ceases completion activities on newly drilled wells due to adverse weather conditions from approximately December to mid-March. In the Williston Basin, QEP drills and completes wells throughout the year, but adverse weather conditions can impact drilling and field operations.

Significant Customers

The Company's five largest customers accounted for 33%, 38%, and 27%, in the aggregate, of QEP's revenues for the years ended December 31, 2014, 2013 and 2012, 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, 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 and Arrow Midstream Holdings, LLC accounted for 13% and 11%, respectively, of the Company's total revenues. During the year ended December 31, 2012, no customer accounted for 10% or more of QEP's total revenues.

Employees

At December 31, 2014, QEP had 765 employees compared to 1,001 employees at December 31, 2013. None of QEP's employees are represented by unions or covered by collective bargaining agreements. The decrease in the number of employees from December 31, 2013 is primarily due to the Midstream Sale.

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, 2015, are listed below:

Charles B. Stanley	56	Chairman (2012 to present). President and Chief Executive Officer (2010 to present). Previous titles with Questar: 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	56	Executive Vice President and Chief Financial Officer (2010 to present). Treasurer (2010 to 2014). Chief Accounting Officer (2013 to 2014). Previous titles with Questar: 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	51	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: Vice President, Drilling and Completions (2009 to 2010); Vice President, Rockies Drilling and Completions (2005 to 2008).
Austin S. Murr	61	Senior Vice President - Business Development (2012 to present). Vice President - Land and Business Development (2010 - 2012). Previous titles with Questar: Vice President - Land and Business Development (2006 - 2010); Director of Business Development (2004 to 2006).
Abigail L. Jones	54	Vice President, Compliance and Corporate Secretary (2010 to present). Previous titles with Questar: Vice President Compliance (2007 to 2010); Corporate Secretary (2005 to 2010); Assistant Secretary (2004 to 2005).
Christopher K. Woosley	45	Vice President and General Counsel (2012 to present). 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	51	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.

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 the recent decline in such prices could adversely affect QEP's results, stock price and growth plans. Our revenues, operating results and future rate of growth depend highly upon the prices we receive for our crude oil, natural gas, and NGL production. Historically gas, oil and NGL prices have been volatile and will likely continue to be volatile in the future. Crude oil prices are influenced by a variety of factors, including global supply and demand, currency values, geopolitical dynamics and other factors. U.S. natural gas prices in particular are significantly influenced by weather and weather forecasts as well as supply and demand. NGL prices generally move in sympathy with natural gas and crude oil prices as well as react to demand for the individual components that make up NGLs. Any significant or extended decline in commodity prices would impact the Company's future financial condition, revenue, operating results, cash flow, return on invested capital, and rate of growth. In addition, significant or extended declines in commodity prices could limit QEP's access to sources of capital or cause QEP to delay or postpone some of its capital projects.

QEP cannot predict the future price of gas, oil and NGL because of factors beyond its control, including but not limited to:

- changes in domestic and foreign supply 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 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;
- political and economic conditions in the United States and in or affecting other producing countries, including conflicts in the Middle East, Africa, South America and Russia;
- the impact of U.S. dollar exchange rates on oil, NGL and natural gas prices;
- weather conditions, weather forecasts 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 for fuel for electricity generation;
- the level of global oil, gas and NGL inventories and exploration and production activity;
- exports from the United States of oil, NGL and natural gas; and
- the quality of oil and gas produced.

During the last quarter of 2014, the prices of oil and natural gas decreased due to an over-supply and decreasing demand. As a result of the current supply and demand fundamentals, the prices of oil and natural gas may stay suppressed for some time compared to the price levels experienced during the last few years. In response to significantly lower commodity prices, we have reduced planned drilling activities and planned capital expenditures, as have many other oil and gas producers. As a result of lower industry activity, we have secured cost decreases from many service providers and expect additional savings going forward. If commodity prices stay depressed or decline further, this could reduce our cash flow from operations and cause us to alter our business plans, including a further reduction or delay of exploration and development spending and other cost reduction initiatives.

Lower commodity prices, such as those experienced recently, may not only decrease our revenues and cash flows but also may reduce the amount of gas, oil and NGL that we can produce economically. In addition, lower commodity prices may result in additional asset impairment charges from reductions in the carrying values of QEP's oil and gas properties. During the years ended December 31, 2014, 2013 and 2012, QEP recorded impairment charges of $1,041.4 million, $1.2 million and $107.6 million, respectively, on its proven properties and $101.8 million, $32.3 million and $25.4 million, respectively, on its unproven properties. During the year ended December 31, 2013, QEP also recorded goodwill impairment of $59.5 million. Forward prices have continued to decline subsequent to the measurement of impairment at December 31, 2014. If commodity prices decline further during 2015, there could be additional impairment charges to our oil and gas assets or other investments. See Part I, Item 8, Note 1 - Summary of Significant Accounting Policies, of this Annual Report on Form 10-K for additional information.

Slower economic growth rates in the U.S. may materially adversely impact QEP's operating results. The U.S. and other economies are recovering from the global financial crisis and recession that began in 2008. Growth has resumed but has been modest and at an unsteady rate. There could be significant long-term effects resulting from the financial crisis and recession, including a future global economic growth rate that is slower than that experienced in the years leading up to the crisis, and 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. A lower future economic growth rate is likely to result in more modest or decreased demand growth for QEP's gas, oil and NGL production. A decrease in demand, excluding changes in other factors, could potentially result in lower commodity prices, which would reduce QEP's 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 QEP 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.

Oil and gas reserve estimates are imprecise and subject to revision. 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.

Shortages of, and increasing prices for, oilfield equipment, services and qualified personnel could impact results of operations. 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 fluctuate significantly, often in correlation with oil and gas prices, causing periodic shortages. There have also been regional shortages of drilling rigs and other equipment, as demand for specialized rigs and equipment has increased along with the number of wells being drilled. These factors also cause increases in costs for equipment, services and personnel. These cost increases could impact profit margin, cash flow and operating results or restrict the ability to drill wells and conduct operations, especially during periods of lower oil and gas prices. Decreases in the costs of these services typically lag declines in oil and natural gas prices.

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 oil, natural gas and NGLs, 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 terroristic acts;
- theft or vandalism of oilfield equipment and supplies, especially in areas of increased activity;
- severe weather that could affect QEP's operations;
- 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 attorney's 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 our wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running our casing the entire length of the wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

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

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

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 and 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. Because wells drilled on a pad are not brought into production until all wells on the pad are drilled and completed and the drilling rig is moved from the location, multi-well pad drilling delays the commencement of production, which may cause volatility in QEP’s quarterly operating results.

Lack of availability of refining, storage or transportation capacity will likely impact results of operations. The lack of availability of satisfactory oil, gas and NGL transportation, including trucks, railways and pipelines, storage or refining capacity may hinder QEP's access to oil, NGL and gas markets or delay production from its wells. QEP's ability to market its production depends in substantial part on the availability and capacity of transportation, 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 transportation or storage facilities do not exist near producing wells, if transportation, storage or refining capacity is limited or if transportation 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 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.

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’s management team 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 depends on 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, 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 numerous 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 its midstream service providers based on minimum volumes regardless of actual volume throughput. QEP has contracts with third-party service providers for transportation services with minimum volume delivery commitments. As of December 31, 2014, QEP’s aggregate long-term contractual obligation under these agreements was $978.3 million. QEP is obligated to pay fees on minimum volumes to service providers regardless of actual volume throughput, which fees could be significant and have a material adverse effect on its 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. The Company utilizes its revolving credit facility, provided by a group of financial institutions, to meet short-term funding needs. All of QEP's debt under its revolving credit facility is floating-rate debt. 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.

A downgrade in QEP's credit rating could negatively impact QEP's cost of and ability to access capital. Although QEP is not aware of any current plans of credit rating agencies to lower their ratings on QEP's debt, QEP's credit ratings may be subject to future downgrades. A downgrade of credit ratings may make it more difficult or expensive to raise capital from financial institutions or other sources. A downgrade in QEP's credit rating below a certain level could limit the amount of debt that QEP may incur. In addition, a downgrade could affect QEP's requirements to provide financial assurance of its performance under certain contractual arrangements and derivative agreements.

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, 2014. 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, to pay dividends to shareholders, 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 engage in transactions with affiliates.

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, joint interest and working interest owners as well as customers in all segments of its business. Because QEP is the operator of a majority of its production and major development projects, QEP pays joint venture expenses and in some cases makes cash calls on its non-operating partners for their respective shares of joint venture costs. These projects are capital intensive and, in some cases, a non-operating partner may experience a delay in obtaining financing for its share of the joint venture costs. Counterparty liquidity problems could result in a delay 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 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;
- 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;
- 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 products;
- other adverse effects on QEP's ability to develop its properties and increase production;
- regulation of rail transportation of crude oil; and
- construction of new oil and gas transmission pipelines.

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'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 enters into commodity-price derivative arrangements with creditworthy counterparties (banks and energy-trading firms) that do not require collateral deposits. QEP is exposed to the risk of counterparties not performing. The amount of credit available may vary depending on QEP's counterparty's assessment of QEP's credit risk.

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 Williston Basin Acquisition completed in September 2012 and its 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.

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 hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical.

QEP 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 liability 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, or injunctions that could limit the scope of QEP's planned operations.

New federal 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 EPA, which may result in more stringent air quality controls and requirements for QEP’s operations. For example, on January 14, 2015, the White House and the U.S. Environmental Protection Agency indicated that they plan to amend the Subpart OOOO standards to achieve additional methane and volatile organic compound reductions from the oil and natural gas industry. These potential amendments to Subpart OOOO could result in additional regulatory requirements and standards for completions of hydraulically fractured oil wells, pneumatic pumps, and leaks from new and modified oil and gas exploration, production, and gathering facilities. A proposed rule is expected in 2015, with a final rule expected in 2016. Additionally, many states are adopting more stringent air permitting and other air quality control regulations specific to oil and gas exploration, production, gathering and processing that go beyond the requirements of federal regulations.

On December 17, 2014, the EPA proposed to revise and lower the existing 75 parts per billion (ppb) national ambient air quality standard (NAAQS) for ozone under the federal Clean Air Act to a range within 65-70 ppb. EPA is also taking public comment on whether the ozone NAAQS should be revised as low as 60 ppb. A lowered ozone NAAQS in a range of 60-70 ppb could result in a significant expansion of ozone nonattainment areas across the United States, including areas in which QEP operates. Oil and natural gas operations 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.

FERC has jurisdiction over the operation of QEP Marketing's Clear Creek 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.

Requirements to reduce gas flaring could have an adverse effect on our operations. Wells in the Bakken and Three Forks formations in North Dakota, where we have significant operations, produce natural gas as well as crude oil. Constraints in the current gas gathering network in certain areas have resulted in some of that natural gas being flared instead of gathered, processed and sold. The North Dakota Industrial Commission, North Dakota's chief energy regulator, recently issued an order to reduce the volume of natural gas flared from oil wells in the Bakken and Three Forks formations. In addition, the Commission is requiring 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 Bureau of Land Management (BLM) has also indicated its intent to pursue a rulemaking related to further controlling the venting and flaring of natural gas on BLM land. 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. The U.S. Department of Transportation has started rulemaking to develop new requirements for shipping crude oil by rail. On December 9, 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 is effective April 1, 2015. 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 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 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 and 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 Energy leasehold due to wildlife activity and/or habitat. QEP Energy 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 Energy is allowed to drill and complete wells year-round in one of five Concentrated Development Areas.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation. The U.S. President's Fiscal Year 2015 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 incentives currently available to oil and gas exploration and production companies. 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, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. 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 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 drilling operations on tribal lands within the Williston Basin in North Dakota and Vermillion Basin in Wyoming continue to be delayed due to substantial backlog of permit applications. 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.

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 federal 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, the BLM proposed in May 2012, 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. 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, the EPA is considering regulation of wastewater discharges from hydraulic fracturing and other natural gas production under the federal Clean Water Act. The EPA is also collecting information as part of a nationwide study into the effects of hydraulic fracturing on drinking water. The EPA issued a progress report regarding the study in December 2012, which described generally the continuing focus of the study, but did not provide any data, findings, or conclusions regarding the safety of hydraulic fracturing operations. The EPA intends to issue a final draft report for peer review and comment at the completion of the study. The results of this study, which is still ongoing, 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, on January 7, 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 EPCRA's Toxics Release Inventory (TRI) program.

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. 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. As noted above, 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 and cause delays, interruptions or termination of its operations, the extent of which cannot be predicted.

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, is considering additional amendments to 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. The Court held that stationary sources already subject to the Prevention of Significant Deterioration (PSD) or Title V permitting programs for non-GHG criteria pollutants remain subject to GHG Best Available Control Technology (BACT) and major source permitting requirements, but ruled that sources cannot be subject to the PSD or Title V major source permitting programs based solely on GHG emission levels. Upon remand, 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 federal government is 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 that may or may not be the result of 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.

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 Wall Street Reform and Consumer Protection Act (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 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 defined benefit pension plan that covers 62 active and suspended participants, or 8%, of QEP's active employees and 152 participants who are retired or were terminated and vested. QEP also sponsors an unfunded Supplemental Executive Retirement Plan. 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, 2014 and 2013, QEP's pension plans were underfunded by $51.2 million and $46.3 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 $13.0 million and $11.5 million during the years ended December 31, 2014 and 2013, respectively, to its defined benefit pension plans and expects to make contributions of approximately $8.4 million to its pension plans in 2015. 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 subject 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, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents. We do not maintain specialized insurance for possible liability resulting from a cyberattack on our assets that may shut down all or part of our business.

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 core 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 targeting the Lance Pool, which is a tight gas sand reservoir. The top of the Lance Pool reservoir ranges from 8,500 to 9,500 feet across QEP Energy's acreage. The Company currently estimates that there are up to 400 additional wells required to fully develop its Pinedale acreage on 5 to 10-acre density. On December 31, 2014, QEP Energy had four operated rigs drilling on the Pinedale Anticline. In addition to QEP Energy's 903 gross producing wells, QEP Energy has an overriding royalty interest in an additional 60 wells at Pinedale.

Williston Basin
QEP Energy has approximately 116,000 net acres in the Williston Basin in western North Dakota, where the Company is targeting the Bakken and Three Forks formations. The Company has been successful in lowering development well costs, de-risking unproven reserves, increasing production, increasing the number of future drilling locations and increasing its estimate of recoverable reserves. The top of the Bakken Formation ranges from approximately 9,500 feet to 10,000 feet across QEP Energy's leasehold. The Three Forks Formation lies approximately 60 to 70 feet below the Middle Bakken Formation and is also a target for horizontal drilling. As of December 31, 2014, QEP Energy had six operated rigs drilling in the Williston Basin.

Uinta Basin
The majority of the Uinta Basin proved reserves are found in a series of vertically stacked, laterally discontinuous reservoirs at depths of 4,500 feet to deeper than 18,000 feet. QEP Energy owns working interests in approximately 232,000 net acres in the Uinta Basin. QEP Energy had one operated rig drilling in the Uinta Basin at December 31, 2014, targeting the Lower Mesaverde Formation productive fairway in which QEP Energy holds 32,300 net acres in the 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 has approximately 26,500 net acres of producing and undeveloped properties that were acquired through the Permian Basin Acquisition in the first quarter of 2014. The Company is targeting oil dominant zones from the Upper Spraberry formation down to the Atoka formation with a combination of horizontal and vertical wells. As of December 31, 2014, QEP Energy had six operated rigs drilling in the Permian Basin.

Haynesville/Cotton Valley
QEP Energy holds approximately 50,500 net acres of 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, 2014, QEP Energy did not have any operated rigs drilling in the Haynesville/Cotton Valley area, however, there were six gross non-operated wells drilling and 21 gross non-operated wells waiting on completion as of December 31, 2014.

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 other non-core properties within this area. As of December 31, 2014, QEP Energy did not have any operated rigs drilling in the Midcontinent area.

Reserves – QEP Energy

At December 31, 2014 and 2013, approximately 93% and 89%, respectively, of QEP Energy's estimated proved reserves were Company operated. Proved developed reserves represented 56% and 53% of the Company's total proved reserves at December 31, 2014 and 2013, 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, 2014				December 31, 2013			
	Gas (Bcf)	**Oil (MMbbl)**	**NGL (MMbbl)**	**Total (Bcfe)[(1)]**	Gas (Bcf)	Oil (MMbbl)	NGL (MMbbl)	Total (Bcfe)[(1)]
Proved developed reserves	**1,288.4**	**99.3**	**52.2**	**2,197.5**	1,406.3	71.8	52.8	2,154.0
Proved undeveloped reserves	**1,028.8**	**73.2**	**44.4**	**1,734.4**	1,148.6	76.8	49.8	1,907.9
Total proved reserves	**2,317.2**	**172.5**	**96.6**	**3,931.9**	2,554.9	148.6	102.6	4,061.9

(1) Oil and NGL are converted to natural gas equivalents at the ratio of one bbl 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, 2012, through December 31, 2014, 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)
2012	3,936.1	319.2	12.3
2013	4,061.9	309.0	13.1
2014	**3,931.9**	**322.7**	**12.2**

(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,			
	2014		2013	
Northern Region	**(Bcfe)**	**(% of total)**	(Bcfe)	(% of total)
Pinedale	**1,450.1**	**37%**	1,563.2	39%
Williston Basin	**858.9**	**22%**	797.5	20%
Uinta Basin	**623.0**	**16%**	586.4	14%
Other Northern	**94.0**	**2%**	92.6	2%
Southern Region				
Haynesville/Cotton Valley	**493.9**	**13%**	502.8	12%
Permian Basin	**375.7**	**10%**	—	—%
Midcontinent	**36.3**	**—%**	519.4	13%
Total QEP Energy	**3,931.9**	**100%**	4,061.9	100%

Estimates of the quantity of proved reserves decreased during 2014 primarily due to sales of reserves in place related to the 2014 Midcontinent property sales and decreases in estimated proved reserves in Pinedale due to production decline on older wells and fewer proved undeveloped (PUD) reserves locations. These proved reserve decreases were partially offset by reserve additions associated with the Permian Basin Acquisition that occurred during the first quarter of 2014 and increases in estimated Williston Basin proved reserves, primarily the result of extensions and additions from the recognition of additional PUD locations due to the increased drilling program.

Proved Undeveloped Reserves

Significant changes to PUD that occurred during 2014 are summarized in the table below:

	2014
	(Bcfe)
Proved undeveloped reserves at January 1,	1,907.9
Transferred to proved developed reserves	**(368.5)**
Revisions to previous estimates	**(55.1)**
Extensions and discoveries[1]	**208.2**
Purchase of reserves in place[2]	**216.5**
Sale of reserves in place[3]	**(174.6)**
Proved undeveloped reserves at December 31,[4]	**1,734.4**

(1) The increase in extensions and discoveries in 2014 was the result of 123.5 Bcfe in Pinedale and 84.7 Bcfe in the Williston Basin. All of these extensions and discoveries related to new well completions and the associated new PUD locations as part of the Company's development drilling plans and new compression projections in Pinedale.

(2) Purchase of reserves in place in 2014 related to the Company's Permian Basin Acquisition as discussed in Note 2 - Acquisitions and Divestitures.

(3) Sale of reserves in place related primarily to property sales in the Midcontinent in the second and fourth quarters of 2014 as discussed in Note 2 - Acquisitions and Divestitures.

(4) All of QEP Energy's PUD reserves at December 31, 2014, 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 $796.7 million, $645.9 million, and $513.0 million for the years ended December 31, 2014, 2013 and 2012, respectively. The costs incurred in 2014 related to the drilling of PUD locations in QEP's development projects. This investment resulted in the transfer of 368.5 Bcfe of PUD reserves to proved developed reserves in 2014, representing 19% of the Company's total PUD reserves as of December 31, 2013.

Estimated future development costs relating to the development of PUD reserves are projected to be approximately $925.7 million in 2015, $983.7 million in 2016, and $714.3 million in 2017. Estimated future development costs include capital spending on major development projects, some of which will take several years to complete. 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, 2014, of which RSC prepared approximately 91% and D&M prepared approximately 9% of the Company's total net proved reserves. The Company utilized RSC to prepare the estimates of 100% of the Company's total net proved reserves as of December 31, 2013 and 2012. The individual at RSC who was responsible for overseeing the preparation of QEP's reserve estimates as of December 31, 2014, 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, 2014, 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 30 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 20 years of experience in the petroleum industry, including more than 15 years reservoir engineering experience in most of the active domestic basins in the U.S.

To establish 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 December 2014, 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 95% of QEP's proved developed non-producing and undeveloped reserves included in this Annual Report on Form 10-K were estimated by analogy. The remaining 5% 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 December 2014. 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, 2014, 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

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, 2014, 2013 and 2012:

	Year Ended December 31,		
	2014	2013	2012
QEP Energy			
Volumes produced and sold			
Gas (Bcf)	**179.3**	218.9	249.3
Oil (Mbbl)	**17,146.5**	10,209.7	6,306.9
NGL (Mbbl)	**6,769.1**	4,811.3	5,349.0
Total equivalent production (Bcfe)	**322.7**	309.0	319.2
Average field-level price [1]			
Gas (per Mcf)	**$ 4.33**	$ 3.56	$ 2.68
Oil (per bbl)	**79.79**	89.78	84.45
NGL (per bbl)	**32.95**	39.95	34.43
Lifting costs (per Mcfe)			
Lease operating expense	**$ 0.74**	$ 0.59	$ 0.55
Production taxes	**0.63**	0.51	0.30
Total lifting costs	**$ 1.37**	$ 1.10	$ 0.85

(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	
	2014	2013	2012	**2014 vs 2013**	2013 vs 2012
QEP Energy - Gas (Bcf)					
Northern Region					
Pinedale	**75.0**	80.0	77.4	**(5.0)**	2.6
Williston Basin	**6.6**	2.7	0.9	**3.9**	1.8
Uinta Basin	**17.9**	18.6	16.3	**(0.7)**	2.3
Other Northern	**9.3**	10.3	11.4	**(1.0)**	(1.1)
Southern Region					
Haynesville/Cotton Valley	**49.5**	71.8	112.0	**(22.3)**	(40.2)
Permian Basin	**3.2**	—	—	**3.2**	—
Midcontinent	**17.8**	35.5	31.3	**(17.7)**	4.2
Total production	**179.3**	218.9	249.3	**(39.6)**	(30.4)

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

	Year ended December 31,			Change	
	2014	2013	2012	**2014 vs 2013**	2013 vs 2012
QEP Energy - Oil (Mbbl)					
Northern Region					
Pinedale	**632.0**	657.6	664.4	**(25.6)**	(6.8)
Williston Basin	**13,130.9**	7,026.2	3,029.5	**6,104.7**	3,996.7
Uinta Basin	**893.3**	924.9	890.9	**(31.6)**	34.0
Other Northern	**200.9**	237.7	297.6	**(36.8)**	(59.9)
Southern Region					
Haynesville/Cotton Valley	**35.3**	43.2	43.4	**(7.9)**	(0.2)
Permian Basin	**1,582.2**	—	—	**1,582.2**	—
Midcontinent	**671.9**	1,320.1	1,381.1	**(648.2)**	(61.0)
Total production	**17,146.5**	10,209.7	6,306.9	**6,936.8**	3,902.8

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

	Year ended December 31,			Change	
	2014	2013	2012	**2014 vs 2013**	2013 vs 2012
QEP Energy - NGL (Mbbl)					
Northern Region					
Pinedale	**3,350.2**	1,787.5	3,054.3	**1,562.7**	(1,266.8)
Williston Basin	**1,010.5**	390.0	197.1	**620.5**	192.9
Uinta Basin	**679.0**	463.8	371.1	**215.2**	92.7
Other Northern	**14.9**	36.7	100.1	**(21.8)**	(63.4)
Southern Region					
Haynesville/Cotton Valley	**37.3**	21.3	8.5	**16.0**	12.8
Permian Basin	**511.0**	—	—	**511.0**	—
Midcontinent	**1,166.2**	2,112.0	1,617.9	**(945.8)**	494.1
Total production	**6,769.1**	4,811.3	5,349.0	**1,957.8**	(537.7)

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

	Year ended December 31,			Change	
	2014	2013	2012	**2014 vs 2013**	2013 vs 2012
QEP Energy - Total Production (Bcfe)					
Northern Region					
Pinedale	**98.9**	94.7	99.7	**4.2**	(5.0)
Williston Basin	**91.4**	47.2	20.3	**44.2**	26.9
Uinta Basin	**27.3**	26.9	23.9	**0.4**	3.0
Other Northern	**10.6**	11.9	13.7	**(1.3)**	(1.8)
Southern Region					
Haynesville/Cotton Valley	**49.9**	72.2	112.3	**(22.3)**	(40.1)
Permian Basin	**15.8**	—	—	**15.8**	—
Midcontinent	**28.8**	56.1	49.3	**(27.3)**	6.8
Total production	**322.7**	309.0	319.2	**13.7**	(10.2)

A regional comparison of average field-level prices is shown in the following table:

	Year Ended December 31,			Change	
	2014	2013	2012	**2014 vs 2013**	2013 vs 2012
QEP Energy - Average field-level gas price (per Mcf)					
Northern Region	**$ 4.26**	$ 3.58	$ 2.64	**$ 0.68**	$ 0.94
Southern Region	**4.44**	3.54	2.70	**0.90**	0.84
Average field-level gas price	**4.33**	3.56	2.68	**0.77**	0.88
QEP Energy - Average field-level oil price (per bbl)					
Northern Region	**$ 78.87**	$ 89.35	$ 83.03	**$ (10.48)**	$ 6.32
Southern Region	**85.76**	92.60	89.32	**(6.84)**	3.28
Average field-level oil price	**79.79**	89.78	84.45	**(9.99)**	5.33
QEP Energy - Average field-level NGL price (per bbl)					
Northern Region	**$ 33.22**	$ 46.56	$ 36.17	**$ (13.34)**	$ 10.39
Southern Region	**32.15**	31.65	30.44	**0.50**	1.21
Average field-level NGL price	**32.95**	39.95	34.43	**(7.00)**	5.52

<u>Northern Region</u>

Pinedale

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.

Production from Pinedale decreased 5% to 94.7 Bcfe during 2013 compared to 2012. This decrease in production was primarily a result of lower NGL production due to rejecting ethane throughout the majority of 2013 compared to recovering ethane throughout the majority of 2012. Additionally, QEP had a lower average interest in wells drilled in the 2013 drilling program.

During each of the three years ended December 31, 2014, 2013 and 2012, Pinedale's production represented 31% of QEP Energy's total production.

Williston Basin

In the Williston Basin, production increased 94% to 91.4 Bcfe during 2014 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 Acquisition, 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 2013, production increased 133% to 47.2 Bcfe compared to 2012, 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 Acquisition, which contributed 2,591.6 Mbbls of increased oil and NGL volume. The remaining 1,598.0 Mbbls increase in 2013 is related to increased development drilling on QEP's existing pre-acquisition acreage.

During the years ended December 31, 2014, 2013 and 2012, Williston Basin production represented 28%, 15%, and 6% of QEP Energy's total production, respectively.

Uinta Basin

In the Uinta Basin, production increased 1% to 27.3 Bcfe during 2014, 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 2013, production increased 13% to 26.9 Bcfe due to increased drilling activity in the Lower Mesaverde formation in the Red Wash Unit. NGL production increased 92.7 Mbbls during 2013 compared to 2012, primarily as a result of QEP Energy executing a fee-based cryogenic processing agreement with QEP Field Services for a portion of the Red Wash Unit's gas production in mid-2012, which was partially offset by decreased overall NGL production due to ethane rejection throughout the majority of 2013.

During the years ended December 31, 2014, 2013 and 2012, Uinta Basin production represented 8%, 9%, and 7%, respectively, of QEP Energy's total production.

Other Northern
QEP Energy's 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.

Other Northern production decreased 13% to 11.9 Bcfe during the year ended December 31, 2013 compared to 2012, due to declining production from older wells and the divestiture of certain of QEP's noncore properties in the Northern Region during 2013.

During the year ended December 31, 2014, Other Northern production represented 3% of QEP Energy's total production, compared to 4% for each of the years ended December 31, 2013 and 2012.

Southern Region

Haynesville/Cotton Valley
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 declining production as QEP's drilling program remained suspended in the area due to depressed gas prices and QEP's focus on developing more liquids rich areas during 2014.

Production from the Haynesville Shale and Cotton Valley decreased 36% to 72.2 Bcfe during 2013 when compared to 2012. Decreased production was due to the suspension of QEP's drilling program in the area due to depressed gas prices and QEP's focus on developing more liquids rich areas during 2013.

During the years ended December 31, 2014, 2013 and 2012, Haynesville/Cotton Valley's production comprised 15%, 23%, and 35% of QEP Energy's total production, respectively.

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 was 15.8 Bcfe during the period from February 25, 2014, through December 31, 2014, which comprised 5% of QEP Energy's total production.

Midcontinent
Production in the Midcontinent decreased 49% to 28.8 Bcfe during 2014 when compared to 2013, due primarily to the sale of QEP's interest in properties in the Midcontinent area at the end of the second quarter of 2014.

Production in the Midcontinent grew 14% to 56.1 Bcfe during 2013 compared to 2012, driven by a 494.1 Mbbl increase in NGL production and a 4.2 Bcfe increase in gas production offset by decreased oil production of 61.0 Mbbl. The increase in gas and NGL production was driven by several high rate and high working interest well completions in 2013.

During the years ended December 31, 2014, 2013 and 2012, Midcontinent's production represented 9%, 18%, and 15% of QEP Energy's total production, respectively.

Productive Wells

The following table summarizes the Company's productive wells as of December 31, 2014, all of which are located in the U.S.:

	Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Northern Region						
Pinedale	903	594	—	—	903	594
Williston Basin	—	—	554	226	554	226
Uinta Basin	694	426	1,542	209	2,236	635
Other Northern	539	182	29	9	568	191
Southern Region						
Haynesville/Cotton Valley	815	453	1	—	816	453
Permian Basin	—	—	338	315	338	315
Midcontinent	799	245	46	15	845	260
Total productive wells [1]	3,750	1,900	2,510	774	6,260	2,674

(1) As of December 31, 2014, QEP owned interests in 90 gross wells containing multiple completions.

The term "gross" refers to all wells or acreage in which QEP has a partial working interest and the term "net" refers to QEP's ownership represented by that working 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 gross 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, 2014. "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
Northern Region						
Colorado	173,015	117,181	80,737	19,030	253,752	136,211
Montana	37,897	15,649	331,566	58,038	369,463	73,687
New Mexico	7,740	4,266	24,651	2,476	32,391	6,742
North Dakota	180,779	42,652	193,303	78,206	374,082	120,858
South Dakota	40	40	203,330	107,551	203,370	107,591
Wyoming	314,516	210,266	180,942	123,327	495,458	333,593
Utah	230,726	177,654	174,708	105,016	405,434	282,670
Other	14,215	3,885	156,065	42,217	170,280	46,102
Southern Region						
Arkansas	17,942	10,095	823	2,470	18,765	12,565
Kansas	46,273	20,872	35,579	15,394	81,852	36,266
Louisiana	69,868	62,044	1,444	1,495	71,312	63,539
Oklahoma	139,501	74,947	143,515	50,936	283,016	125,883
Texas	31,179	22,495	12,804	10,445	43,983	32,940
Other	—	—	1,757	1,300	1,757	1,300
Total	**1,263,691**	**762,046**	**1,541,224**	**617,901**	**2,804,915**	**1,379,947**

(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,		
2015	92,572	73,700
2016	29,905	28,439
2017	58,373	54,832
2018	8,468	8,124
2019 and later	39,801	37,016
Total	229,119	202,111

Drilling Activity

The following table summarizes the number of development and exploratory wells drilled during the years indicated:

	Developmental Wells				Exploratory Wells			
	Productive		Dry		Productive		Dry	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
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
Year Ended December 31, 2012								
Northern Region								
Pinedale	102	73.3	—	—	—	—	—	—
Williston Basin	88	28.0	—	—	—	—	—	—
Uinta Basin	254	45.1	—	—	1	0.6	—	—
Other Northern	31	6.6	—	—	—	—	—	—
Southern Region								
Haynesville/Cotton Valley	35	15.7	—	—	2	1.6	—	—
Midcontinent	157	32.2	—	—	—	—	—	—
Total	667	200.9	—	—	3	2.2	—	—

The following table presents operated and non-operated well completions for the year ended December 31, 2014:

	Operated Completions		Non-operated Completions	
	Gross	Net	Gross	Net
Northern Region				
Pinedale	116	82.4	—	—
Williston Basin	88	72.9	111	7.7
Uinta Basin	7	6.0	189	0.5
Other Northern	4	4.0	—	—
Southern Region				
Haynesville/Cotton Valley	—	—	41	3.5
Permian Basin	70	62.9	1	0.3
Midcontinent	1	0.9	31	1.4

The following table presents operated and non-operated wells drilling and waiting on completion at December 31, 2014:

	Operated				Non-operated			
	Drilling		Waiting on completion		Drilling		Waiting on completion	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Northern Region								
Pinedale[(1)]	15	10.2	45	28.8	—	—	—	—
Williston Basin	15	11.7	35	27.4	11	1.6	25	0.8
Uinta Basin	1	1.0	—	—	—	—	—	—
Other Northern	—	—	1	1.0	—	—	—	—
Southern Region								
Haynesville/Cotton Valley	—	—	—	—	6	0.8	21	2.0
Permian Basin	6	5.0	6	5.2	—	—	2	0.9
Midcontinent	—	—	—	—	—	—	9	0.6

(1) QEP suspends Pinedale completion operations during the coldest months of the winter, generally from December to mid-March.

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. As a result, QEP had 87 gross operated wells waiting on completion as of December 31, 2014.

Delivery Commitments

QEP Energy 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)
2015	13.5
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 are 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, none of the Company's production from QEP Energy's owned properties is subject to any priorities, proration or third-party imposed curtailments that may affect quantities delivered to its customers, any 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.

Energy Marketing – QEP Marketing and Other

QEP Marketing owns and operates an underground gas storage reservoir in southwestern Wyoming. The reservoir has a gas storage 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 and operates the Haynesville Gathering System, located in Louisiana. The Haynesville Gathering System 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.

Delivery Commitments
QEP Marketing 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)
2015	86.5
2016	11.1
2017	0.9
2018	0.5
Thereafter	—

These commitments are physical delivery obligations with prices based on prevailing index prices for gas at the time of delivery. Historically, QEP Marketing has materially fulfilled its delivery commitments by purchasing and selling QEP Energy's gas production. The Company believes that QEP Energy's gas production and reserves to be sold to QEP Marketing are adequate to meet these long-term sales commitments. If for some reason QEP Energy's gas production sold to QEP Marketing 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, for discussion of firm transportation and storage commitments related to gas deliveries.

ITEM 3. LEGAL PROCEEDINGS

In the ordinary course of its business, QEP is a defendant in a number of lawsuits and is involved in governmental proceedings and regulatory controls. QEP is also subject to various environmental remediation and reclamation obligations arising from federal, state, and local laws and regulations. While the ultimate outcome and impact on QEP cannot be predicted with certainty, management does not believe that the resolution of pending proceedings will materially affect the Company's consolidated financial position, results of operations, or cash flows.

See Note 10 - Commitments and Contingencies, in Item 8 of Part II of this Annual Report on Form 10-K for disclosures regarding certain legal proceedings.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

QEP's common stock is listed and traded on the New York Stock Exchange (NYSE:QEP). As of January 31, 2015, QEP had 6,359 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. The Company expects that cash dividends will continue to be paid in the future.

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 2014 and 2013:

	High price	Low price	Dividend
		(per share)	
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**
2013			
First quarter	$ 32.90	$ 28.82	$ 0.02
Second quarter	31.75	26.24	0.02
Third quarter	31.52	27.23	0.02
Fourth quarter	34.24	27.64	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.

QEP's 2014 peer group consisted of the following:

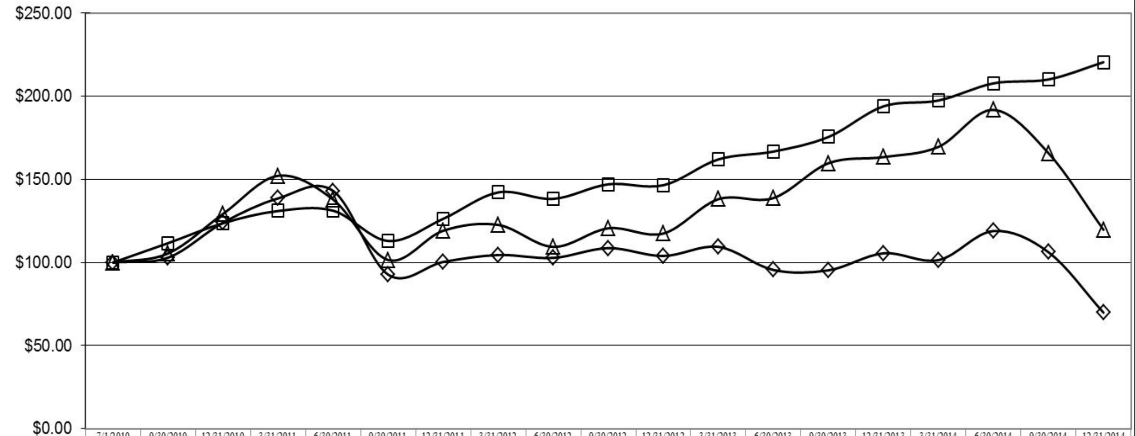
Cabot Oil & Gas Corporation
Cimarex Energy Company
Concho Resources
Denbury Resources Inc.
Forest Oil Corporation
Newfield Exploration Company
Noble Energy, Inc.
Quicksilver Resources, Inc.
Pioneer Natural Resources Company
Range Resources Corporation
SM Energy
Southwestern Energy Company
Ultra Petroleum Corporation
Whiting Petroleum Corporation
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 peer group as of July 1, 2010, which is the date when QEP's common stock began trading on the NYSE;

- Investment in the Company's peer group was weighted based on the stock market capitalization of each individual company within the peer group at the beginning of each period for which a return is indicated; and
- Dividends were reinvested on the relevant payment dates.

Comparison of 54 Month Cumulative Total Return
Assumes Initial Investment of $100
December 2014



	7/1/2010	9/30/2010	12/31/2010	3/31/2011	6/30/2011	9/30/2011	12/31/2011	3/31/2012	6/30/2012	9/30/2012	12/31/2012	3/31/2013	6/30/2013	9/30/2013	12/31/2013	3/31/2014	6/30/2014	9/30/2014	12/31/2014
QEP Resources, Inc.	100.00	102.90	124.03	138.56	143.03	92.61	100.30	104.48	102.74	108.61	103.92	109.39	95.51	95.26	105.51	101.41	118.91	106.15	69.79
S&P 500 Index - Total Returns	100.00	111.65	123.66	130.98	131.11	112.93	126.27	142.16	138.25	147.03	146.48	162.01	166.73	175.47	193.92	197.42	207.76	210.10	220.46
Peer Group	100.00	105.43	129.28	152.17	137.77	101.44	119.10	122.58	109.38	120.57	117.41	138.08	138.75	159.69	163.41	169.53	191.79	165.75	119.63

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

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 was extended through December 2015. The timing and amount of any QEP share repurchases will depend upon a number of factors, including general market conditions, the Company’s financial position and the estimated intrinsic value of the Company’s shares. The repurchase plan does not obligate QEP to acquire any specific number of shares and may be discontinued at any time. During December 2014, QEP repurchased 4,731,438 shares at a weighted average price of $21.08 per share, including commission of $0.02 per share, for $99.7 million under this program.

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

Period	Total shares purchased [(1)]	Weighted-average price paid per share	Total shares purchased as part of publicly announced plans or programs	Maximum value that may yet be purchased under the plans or programs
				(in millions)
October 1, 2014 - October 31, 2014	151	$ 21.85	—	—
November 1, 2014 - November 30, 2014	1,979	$ 24.64	—	—
December 1, 2014 - December 31, 2014	4,789,920	$ 21.08	4,731,438	$ 400.3

(1) 60,612 of the shares purchased during the three-month period ended December 31, 2014, were acquired from employees in connection with the settlement of income tax and related benefit withholding obligations arising from vesting in restricted stock grants.

ITEM 6. SELECTED FINANCIAL DATA

Selected financial data for the five years ended December 31, 2014, is provided in the table below. Our financial results for 2014 and for prior periods have been revised, in accordance with GAAP, to reflect the impact of the Midstream Sale. See footnote (3) 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,				
	2014 [1][2]	2013[1]	2012[1]	2011	2010
	(in millions, except per share information)				
Results of Operations					
Revenues [3]	**$ 3,414.3**	$ 2,685.1	$ 2,071.7	$ 2,835.0	$ 2,107.3
Operating income (loss)	**(847.3)**	203.0	(321.2)	267.2	410.9
Income (loss) from continuing operations	**(409.5)**	52.1	2.4	118.1	200.4
Discontinued operations, net of income tax[4]	**1,193.9**	107.3	125.9	149.1	125.8
Net income attributable to QEP	**784.4**	159.4	128.3	267.2	326.2
Earnings (loss) per common share attributable to QEP					
Basic from continuing operations	**$ (2.28)**	$ 0.29	$ 0.01	$ 0.67	$ 1.14
Basic from discontinued operations[4]	**6.64**	0.60	0.71	0.84	0.72
Basic total	**$ 4.36**	$ 0.89	$ 0.72	$ 1.51	$ 1.86
Diluted from continuing operations	**$ (2.28)**	$ 0.29	$ 0.01	$ 0.66	$ 1.13
Diluted from discontinued operations[4]	**6.64**	0.60	0.71	0.84	0.71
Diluted total	**$ 4.36**	$ 0.89	$ 0.72	$ 1.50	$ 1.84
Dividends per share	**$ 0.08**	$ 0.08	$ 0.08	$ 0.08	$ 0.04
Weighted-average common shares outstanding					
Used in basic calculation	**179.8**	179.2	177.8	176.5	175.3
Used in diluted calculation	**179.8**	179.5	178.7	178.4	177.3
Financial Position					
Total Assets at December 31,	**$ 9,286.8**	$ 9,408.9	$ 9,108.5	$ 7,442.7	$ 6,785.3
Capitalization at December 31,					
Long-term debt	**2,218.1**	2,997.5	3,206.9	1,679.4	1,530.8
Total equity	**4,075.3**	3,876.8	3,313.7	3,352.1	3,063.1
Total Capitalization	**$ 6,293.4**	$ 6,874.3	$ 6,520.6	$ 5,031.5	$ 4,593.9
Cash Flow from Operations					
Net cash provided by operating activities	**$ 1,542.5**	$ 1,191.7	$ 1,296.0	$ 1,292.6	$ 1,060.0
Capital expenditures	**(2,726.4)**	(1,602.6)	(2,799.7)	(1,431.1)	(1,508.9)
Net cash provided by (used in) investing activities	**578.2**	(1,441.5)	(2,794.5)	(1,422.9)	(1,483.1)
Net cash (used in) provided by financing activities	**(990.6)**	279.8	1,498.5	130.3	405.6
Non-GAAP Measure					
Adjusted EBITDA [5]	**$ 1,582.7**	$ 1,536.7	$ 1,409.0	$ 1,380.7	$ 1,178.1

(1) During the years ended December 31, 2014, 2013 and 2012, the results are impacted by the Williston Basin Acquisition that occurred on September 27, 2012. See Note 2 - Acquisitions and Divestitures, in Item 8 of Part II this Annual Report on Form 10-K for detailed information on the Williston Basin Acquisition.

(2) During the year ended December 31, 2014, the results are impacted by the Permian Basin Acquisition that occurred on February 25, 2014, and the property sales in the Midcontinent that occurred during the second quarter 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 years ended December 31, 2011, and 2010, reflect the impact of QEP's settled derivative contracts, which during the years ended December 31, 2014, 2013 and 2012, are 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, 2014, 2013 and 2012.

(4) 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. Additionally, in June 2010, QEP completed a Spin-off from Questar. As a result of the Spin-off, Wexpro, a fully owned subsidiary of QEP, was distributed to Questar. Wexpro's financial results have been reflected as discontinued operations in 2010.

(5) 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,				
	2014	2013	2012	2011	2010
	(in millions)				
Net income attributable to QEP	**$ 784.4**	$ 159.4	$ 128.3	$ 267.2	$ 326.2
Discontinued operations, net of tax	**(1,193.9)**	(107.3)	(125.9)	(149.1)	(125.8)
Income (loss) from continuing operations	**(409.5)**	52.1	2.4	118.1	200.4
Unrealized (gains) losses on derivative contracts	**(374.4)**	88.7	(63.2)	(117.7)	(121.7)
Net (gain) loss from asset sales	**148.6**	(103.5)	(1.2)	(1.4)	(13.7)
Interest and other income	**(12.8)**	(15.2)	(15.0)	(9.2)	(2.3)
Income tax provision (benefit)	**(232.5)**	60.1	(1.9)	65.5	120.7
Interest expense	**169.1**	165.1	126.3	92.1	79.0
Accrued litigation loss contingency	**—**	—	115.0	—	—
Separation costs[1]	**—**	—	—	—	13.5
Loss from early extinguishment of debt	**2.0**	—	0.6	0.7	13.3
Depreciation, depletion and amortization	**994.7**	963.8	850.2	716.9	598.6
Impairment	**1,143.2**	93.0	133.0	218.2	46.1
Exploration expenses	**9.9**	11.9	11.2	10.5	23.0
Adjusted EBITDA from continuing operations	**1,438.3**	1,316.0	1,157.4	1,093.7	956.9
Adjusted EBITDA from discontinued operations [2]	**144.4**	220.7	251.6	287.0	221.2
Adjusted EBITDA	**$ 1,582.7**	$ 1,536.7	$ 1,409.0	$ 1,380.7	$ 1,178.1

(1) Separation costs represent costs incurred by QEP related to QEP's Spin-off from Questar in June 2010. Separation costs incurred by QEP related to the Midstream Sale in 2014 are included in "Discontinued operations, net of tax".

(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.

The following information updates the discussion of QEP's financial condition provided in its 2013 Annual Report on Form 10-K filing, and analyzes the changes in the results of operations between the years ended December 31, 2014 and 2013, and between the years ended December 31, 2013 and 2012.

OVERVIEW

QEP Resources, Inc. (QEP or the Company) is a holding company with two lines of business: oil and gas exploration and production (QEP Energy) and oil and gas marketing, operation of the Haynesville Gathering System and an underground gas storage reservoir (QEP Marketing and Other).

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 E&P business. During 2014, which includes ten months of results from the properties acquired in the Permian Basin, QEP Energy increased its oil and NGL production by 59% compared to 2013. Additionally, oil and NGL revenue represented 67% of QEP Energy's field-level revenue during the year ended December 31, 2014, up from 59% during the year ended December 31, 2013 and 52% during the year ended December 31, 2012.

Discontinued Operations

In October 2014, the Company announced that its wholly owned subsidiary, QEP Field Services Company (QEP Field Services), had entered into a definitive agreement to sell substantially all of its midstream business, including the Company's ownership interest in QEP Midstream Partners, LP (QEP Midstream), to Tesoro Logistics LP (Tesoro). On December 2, 2014, QEP closed the sale of its midstream business to Tesoro (Midstream Sale) for total cash proceeds of $2.5 billion, including $230.0 million to refinance debt at QEP Midstream, subject to post-closing adjustments, and QEP recorded a pre-tax gain of $1.8 billion on its Consolidated Statements of Operations in "Net income from discontinued operations, net of income tax" for the year ended December 31, 2014. The decision to sell the midstream business was the result of the Company’s ongoing review of strategic alternatives to maximize shareholder value. QEP Marketing retained ownership of the Haynesville Gathering System. As a result of the Midstream Sale, the QEP Field Services reporting segment, excluding the retained ownership of the Haynesville Gathering System, has been classified as a discontinued operation on the Consolidated Statement of Operations and the notes accompanying the Consolidated Financial Statements. For reporting purposes, the retained Haynesville Gathering System has been combined with QEP Marketing and Other.

Acquisitions

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 consist 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 creates a new core area of operation for QEP Energy. The Permian Basin Acquisition was funded with $50.0 million of restricted cash, $300.0 million from the Company's expanded term loan and the remainder from QEP's revolving credit facility. During 2012, QEP Energy acquired oil and gas properties in the Williston Basin for an aggregate purchase price of $1.4 billion (the Williston Basin Acquisition).

While QEP believes that it can grow production and reserves from its extensive inventory of identified drilling locations, 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.

Other Divestitures

The Company will periodically divest select non-core portfolio assets to redirect capital towards higher-return projects. In June 2014, QEP sold its interests in certain non-core properties in the Midcontinent area and other non-core assets in the Williston Basin for aggregate proceeds of approximately $692.9 million, subject to post-closing purchase price adjustments. The Company used proceeds to repay borrowings on its revolving credit facility incurred to fund the Permian Basin Acquisition. In December 2014, QEP sold its interest in certain non-core properties in southern Oklahoma for aggregate proceeds of approximately $94.9 million, subject to post-closing purchase price adjustments. In 2013, QEP divested of certain non-core properties in the Midcontinent and Northern Regions resulting in aggregate proceeds of $205.8 million.

Outlook

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 has a large inventory of lower-risk, predictable development drilling locations across its acreage holdings in the onshore United States that provide a solid base for growth in organic production and reserves.

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 was extended through December 2015. The timing and amount of any QEP share repurchases will depend upon a number of factors, including general market conditions, the Company’s financial position and the estimated intrinsic value of the Company’s shares. The repurchase plan does not obligate QEP to acquire any specific number of shares and may be discontinued at any time. During December 2014, QEP repurchased 4,731,438 shares at a weighted average price of $21.08 per share, including commission of $0.02 per share, for $99.7 million under this program.

Financial and Operating Results

For the years ended December 31, 2014 and 2013, QEP Energy reported total equivalent production of 322.7 Bcfe and 309.0 Bcfe, respectively, an increase of 4% and decrease of 3%, from the respective 2013 and 2012 comparable periods. Oil and NGL production for the years ended December 31, 2014 and 2013, was 23.9 MMbbls and 15.0 MMbbls, respectively, a combined increase of 59% and 29%, when compared to the prior year periods. Contributing to these increases was the Williston Basin Acquisition, which contributed 9.8 MMbbls of oil and NGL production during the year ended December 31, 2014, compared to 3.4 MMbbls during the year ended December 31, 2013. Additionally, QEP Energy completed the Permian Basin Acquisition on February 25, 2014, which contributed 2.1 MMbbls of oil and NGL production during the period from February 25, 2014, to December 31, 2014. These increases were partially offset by decreases in gas production during the years ended December 31, 2014 and 2013, to 179.3 Bcf and 218.9 Bcf, respectively, decreases of 18% and 12%, when compared to the prior year periods. Additionally, these increases were offset by a decrease in the production from the properties in the Midcontinent, which contributed 28.8 Bcfe of total production during the year ended December 31, 2014, a decline from 56.1 Bcfe and 49.3 Bcfe during the years ended December 31, 2013 and 2012, respectively, due to the divestitures of non-core properties in the area during 2014 and 2013.

QEP Energy also benefited from higher average realized prices (including the impact of settled commodity derivatives). For the years ended December 31, 2014, 2013 and 2012, QEP Energy's average realized prices were $7.33 per Mcfe, $6.59 per Mcfe and $5.48 per Mcfe, respectively.

Factors Affecting Results of Operations

Oil, Gas, and NGL Prices
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 Marcellus Shale region, have resulted in downward pressure on U.S. natural gas prices and a high degree of pricing variability among different 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 and adequate storage levels led to natural gas price declines later in the year. Similarly, growth in U.S. oil production in excess of demand growth has led to a dramatic weakening of global oil prices starting in late 2014. NGL prices have also been affected by increased U.S. hydrocarbon production. Pricing of heavier NGL components is typically correlated to crude oil prices, while ethane and propane prices have decreased as a result of oversupply. In addition, QEP's NGL prices are affected by ethane recovery. When ethane is recovered as an NGL instead of being sold as part of the natural gas stream, the average NGL barrel sales price decreases as the ethane price is lower than the prices of the remaining NGL components. QEP recovered ethane for the majority of 2014 and expects to change to ethane rejection due to a recent decline in ethane and propane 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, and costs of goods and services required to drill and complete wells, and the carrying value of its oil and natural gas properties.

During 2014, the NYMEX-WTI oil monthly average spot price ranged from a high of $105.79 per bbl in June to a low of $59.29 per bbl in December, while the NYMEX-HH natural gas one-month future price ranged from a high of $5.15 per MMBtu in February to a low of $3.65 per MMBtu in November. Due to increased uncertainty around the global economic outlook and the volatility of commodity prices, QEP has built a strong liquidity position to ensure financial flexibility. QEP has also planned a flexible capital spending program to allow a rapid response in activity levels should oil or gas prices move substantially. A flexible investment program, together with the Company's commodity derivative program, will support and help maintain the efficiency of QEP's exploration and production activities in a volatile commodity price environment. 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% of its forecasted annual production by the end of the first quarter of each fiscal year. At December 31, 2014, assuming 2015 annual production of approximately 295.5 Bcfe, QEP Energy had approximately 40% of its forecasted total production covered by a combination of fixed-price swaps and costless collars, including 41% of its forecasted gas production and 49% of its forecasted oil 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. In addition, as a result of the continued spread between oil and gas prices, QEP Energy has allocated approximately 96% of its forecasted 2015 drilling and completion capital expenditure budget to oil and liquids-rich gas projects in its portfolio.

Global Geopolitical and Macroeconomic Factors
QEP continues to monitor the outlook of the global economy, including political unrest in Eastern Europe, the Middle East, and Africa; a slowing of growth in Europe and Asia; the United States' federal budget deficit; the potential for future shut-downs of federal government offices including the Department of Interior (including the Bureau of Land Management (BLM) and Bureau of Indian Affairs (BIA), which process permits to drill and rights-of-way for construction of gathering lines and other midstream infrastructure on federal (BLM) and Native American (BIA and BLM) minerals and surface); changes in regulatory oversight policy; commodity price volatility; 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, 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
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 throughout 2013 and 2014, 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 last half of 2013 and into 2014. Natural gas prices weakened in the second half of 2014 due to more typical 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. This shift in focus has caused domestic NGL production to increase dramatically. Increased NGL production and price dislocations from infrastructure bottlenecks in certain regions have all contributed to a weakening of domestic NGL prices, particularly ethane. QEP expects that ethane prices will continue to be range-bound until new ethylene crackers and export facilities are built. The prices of heavier components of the NGL barrel have weakened as a result of the decline in crude oil prices. Recently, increased oil production in the U.S. combined with various other factors have led to weaker oil prices. According to data from the EIA, U.S. oil production has increased by more than three million barrels per day, or more than 50%, since 2011. International oil supply disruptions in recent years have prevented oversupply and a corresponding negative price impact but reduced supply disruptions in recent months combined with softening global demand, a stronger U.S. dollar, and other factors have led to substantially lower oil prices starting in late 2014. As a result, many oil producers around the world are dramatically reducing activity. QEP anticipates global oil prices will improve in the coming years as supply growth moderates due to lower level of investment. 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. In addition, transportation, refining, or other infrastructure constraints could introduce significant price differentials between regional markets where QEP sells its oil production and national (NYMEX HH at Henry Hub or NYMEX WTI at Cushing) and global (ICE Brent at the U.S. Gulf Coast) markets. Because of the global and regional price volatility and the uncertainty around the natural gas, oil and NGL price environments, QEP continues to manage its capital spending program and liquidity accordingly.

Potential for Future 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 forward prices for gas, oil or NGL prices 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 oil, gas 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. However, a decrease in forward gas, oil or NGL prices alone could result in additional impairment of properties. Forward prices have continued to decline subsequent to the measurement of impairment at December 31, 2014. If commodity prices decline further during 2015, there could be additional impairment charges to our oil and gas assets or other investments.

During the year ended December 31, 2014, the Company recorded impairments of $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 changes in drilling plans. During the year ended December 31, 2012, impairments were $133.0 million primarily due to lower NGL and gas prices resulting in impairments of proved property. 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. Because wells drilled on a pad are not brought into production until all wells on the pad are drilled and completed and the drilling rig is moved from the location, multi-well pad drilling delays the commencement of production, which may cause volatility in QEP’s quarterly operating results.

Critical Accounting Estimates
QEP’s significant accounting policies are described in Item 8 of Part II of this Annual Report on Form 10-K. The Company’s Consolidated Financial Statements are prepared in accordance with GAAP. The preparation of the Company’s Consolidated Financial Statements requires management to make assumptions and estimates that affect the reported results of operations and financial position. QEP’s accounting policies on oil and gas reserves, successful efforts accounting for oil and gas operations, impairment of oil and gas properties, asset retirement obligations, accounting for derivative contracts, revenue recognition, environmental obligations, litigation and other contingencies, benefit plan obligations, equity-based compensation, income taxes, and purchase price allocations, among others, may involve a high degree of complexity and judgment on the part of management.

RESULTS OF OPERATIONS

Our financial results for 2014 and 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

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 primarily due to a decrease of $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 instruments of $150.8 million. These additional expenses incurred at QEP Energy during 2014 were partially offset by an increase in unrealized gains on derivative instruments 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.

QEP generated net income from continuing operations during the year ended December 31, 2013, of $52.1 million, or $0.29 per diluted share, compared to $2.4 million, or $0.01 per diluted share, in 2012. The increase in net income during 2013 was due to a $33.7 million increase in QEP Energy's net income and a $16.0 million increase in QEP Marketing and Other's net income. QEP Energy's net income increase was primarily due to an increase in realized equivalent prices, increased oil volumes, gain from asset sales and lower impairment charges and general and administrative costs partially offset by lower realized gains on derivative instruments, increased production and property taxes and depreciation, depletion and amortization expenses. QEP Marketing and Other's net income is related to intercompany interest income from interest expense charges to QEP's subsidiaries.

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

	Year Ended December 31,			Change	
	2014	2013	2012	**2014 vs 2013**	2013 vs 2012
			(in millions)		
QEP Energy	**$ (432.5)**	$ 25.6	$ (8.1)	**$ (458.1)**	$ 33.7
QEP Marketing and Other	**23.0**	26.5	10.5	**(3.5)**	16.0
Net income (loss) from continuing operations	**(409.5)**	52.1	2.4	**(461.6)**	49.7
Net income from discontinued operations, net of income tax	**1,193.9**	107.3	125.9	**1,086.6**	(18.6)
Net income attributable to QEP	**$ 784.4**	$ 159.4	$ 128.3	**$ 625.0**	$ 31.1
Earnings (loss) per diluted share from continuing operations	**$ (2.28)**	$ 0.29	$ 0.01	**$ (2.57)**	$ 0.28
Earnings per diluted share from discontinued operations	**6.64**	0.60	0.71	**6.04**	(0.11)
Diluted earnings per share	**$ 4.36**	$ 0.89	$ 0.72	**$ 3.47**	$ 0.17
Average diluted shares	**179.8**	179.5	178.7	**0.3**	0.8

Adjusted EBITDA

Management believes Adjusted EBITDA (a non-GAAP measure) is an important measure of the Company’s cash flow, liquidity, and ability to incur and service debt, fund capital expenditures and return capital to shareholders. The use of this measure allows investors to understand how management evaluates financial performance to make operating decisions and allocate resources. It is also an important measure for comparing the Company’s financial performance to other oil and gas producing companies. 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	
	2014	2013	2012	**2014 vs 2013**	2013 vs 2012
			(in millions)		
QEP Energy	**$ 1,437.0**	$ 1,301.8	$ 1,118.4	**$ 135.2**	$ 183.4
QEP Marketing and Other	**1.3**	14.2	39.0	**(12.9)**	(24.8)
Adjusted EBITDA from continuing operations	**1,438.3**	1,316.0	1,157.4	**122.3**	158.6
Discontinued operations	**144.4**	220.7	251.6	**(76.3)**	(30.9)
Adjusted EBITDA	**$ 1,582.7**	$ 1,536.7	$ 1,409.0	**$ 46.0**	$ 127.7

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.

Adjusted EBITDA from continuing operations increased to $1,316.0 million during the year ended December 31, 2013, compared to $1,157.4 million in 2012, due to 5% higher net realized gas prices, 3% higher net realized oil prices, 10% higher realized NGL prices, and a 62% increase in total oil production that was partially offset by lower gas and NGL production volumes 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, 2014, 2013 and 2012:

	QEP Energy	QEP Marketing and Other [1]	Continuing Operations	Discontinued Operations	QEP Consolidated
Year ended December 31, 2014			(in millions)		
Net income (loss) attributable to QEP	**$ (432.5)**	**$ 23.0**	**$ (409.5)**	**$ 1,193.9**	**$ 784.4**
Unrealized (gains) losses 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)[2]	**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[3]	**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) attributable to QEP	$ 25.6	$ 26.5	$ 52.1	$ 107.3	$ 159.4
Unrealized (gains) losses 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)[2]	192.6	(27.5)	165.1	(2.2)	162.9
Depreciation, depletion and amortization[3]	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
Year ended December 31, 2012					
Net income (loss) attributable to QEP	$ (8.1)	$ 10.5	$ 2.4	$ 125.9	$ 128.3
Unrealized (gains) losses on derivative contracts	(68.4)	5.2	(63.2)	—	(63.2)
Net (gain) loss from asset sales	(1.2)	—	(1.2)	—	(1.2)
Interest and other income	(6.2)	(8.8)	(15.0)	8.2	(6.8)
Income tax provision (benefit)	(12.1)	10.2	(1.9)	68.7	66.8
Interest expense (income)	116.8	9.5	126.3	(3.5)	122.8
Accrued litigation loss contingency[4]	115.0	—	115.0	—	115.0
Loss from early extinguishment of debt	—	0.6	0.6	—	0.6
Depreciation, depletion and amortization[3]	838.4	11.8	850.2	52.3	902.5
Impairment	133.0	—	133.0	—	133.0
Exploration expenses	11.2	—	11.2	—	11.2
Adjusted EBITDA	$ 1,118.4	$ 39.0	$ 1,157.4	$ 251.6	$ 1,409.0

(1) Includes intercompany eliminations.

(2) 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.

(3) Excludes noncontrolling interests' share of $14.6 million, $6.8 million, and $2.8 million during the years ended December 31, 2014, 2013 and 2012, respectively, of depreciation, depletion and amortization attributable to Rendezvous Gas Services, L.L.C and QEP Midstream.

(4) Includes certain significant litigation contingency items for the year ended December 31, 2012.

DISCUSSION BY LINE OF BUSINESS

Operating results are discussed by line of business as management believes it provides a more meaningful analysis than consolidated results. Other consolidated results, such as general and administrative expenses, interest, derivative instruments, income taxes and other non-operating items, are discussed elsewhere in Management's Discussion and Analysis of Financial Condition and Results of Operations.

Our financial results for 2014 and 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.

QEP Energy

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

	Year Ended December 31,			Change	
	2014	2013	2012	**2014 vs 2013**	2013 vs 2012
	(in millions)				
Revenues					
Gas sales	**$ 776.4**	$ 779.0	$ 667.4	**$ (2.6)**	$ 111.6
Oil sales	**1,368.2**	916.6	532.6	**451.6**	384.0
NGL sales	**223.1**	192.2	184.2	**30.9**	8.0
Purchased gas sales	**150.0**	191.6	222.0	**(41.6)**	(30.4)
Other	**6.9**	13.4	9.2	**(6.5)**	4.2
Total Revenues	**2,524.6**	2,092.8	1,615.4	**431.8**	477.4
Operating expenses					
Purchased gas expense	**150.0**	197.1	224.7	**(47.1)**	(27.6)
Lease operating expense	**240.1**	181.3	175.8	**58.8**	5.5
Gas, oil and NGL transportation and other handling costs	**291.5**	242.2	228.1	**49.3**	14.1
General and administrative	**201.3**	160.6	252.8	**40.7**	(92.2)
Production and property taxes	**204.0**	159.8	97.2	**44.2**	62.6
Depreciation, depletion and amortization	**984.4**	954.2	838.4	**30.2**	115.8
Exploration expenses	**9.9**	11.9	11.2	**(2.0)**	0.7
Impairment	**1,143.2**	93.0	133.0	**1,050.2**	(40.0)
Total Operating Expenses	**3,224.4**	2,000.1	1,961.2	**1,224.3**	38.9
Net gain (loss) from asset sales	**(148.6)**	104.1	1.2	**(252.7)**	102.9
Operating Income (Loss)	**(848.4)**	196.8	(344.6)	**(1,045.2)**	541.4
Realized gains (losses) on derivative instruments	**(1.0)**	149.8	366.5	**(150.8)**	(216.7)
Unrealized gains (losses) on derivative instruments	**368.2**	(90.7)	68.4	**458.9**	(159.1)
Interest and other income	**11.8**	3.6	6.2	**8.2**	(2.6)
Income from unconsolidated affiliates	**0.3**	0.2	0.1	**0.1**	0.1
Interest expense	**(210.3)**	(192.6)	(116.8)	**(17.7)**	(75.8)
Income (loss) from continuing operations before income taxes	**(679.4)**	67.1	(20.2)	**(746.5)**	87.3
Income tax (provision) benefit	**246.9**	(41.5)	12.1	**288.4**	(53.6)
Net income (loss) attributable to QEP	**$ (432.5)**	$ 25.6	$ (8.1)	**$ (458.1)**	$ 33.7
Production volumes					
Gas (Bcf)	**179.3**	218.9	249.3	**(39.6)**	(30.4)
Oil (Mbbl)	**17,146.5**	10,209.7	6,306.9	**6,936.8**	3,902.8
NGL (Mbbl)	**6,769.1**	4,811.3	5,349.0	**1,957.8**	(537.7)
Total production (Bcfe)	**322.7**	309.0	319.2	**13.7**	(10.2)
Daily combined production (MMcfe/d)	**884.0**	846.5	872.1	**37.5**	(25.6)

Revenue

A comparison of net realized average gas, oil and NGL prices, including the realized gains and losses on commodity derivative contracts, is provided in the following table:

	Year Ended December 31,			Change	
	2014	2013	2012	**2014 vs 2013**	2013 vs 2012
Gas (per Mcf)					
Average field-level price	**$ 4.33**	$ 3.56	$ 2.68	**$ 0.77**	$ 0.88
Commodity derivative impact	**(0.09)**	0.69	1.37	**(0.78)**	(0.68)
Net realized price	**$ 4.24**	$ 4.25	$ 4.05	$ (0.01)	$ 0.20
Oil (per bbl)					
Average field-level price	**$ 79.79**	$ 89.78	$ 84.45	**$ (9.99)**	$ 5.33
Commodity derivative impact	**0.92**	(0.22)	2.28	**1.14**	(2.50)
Net realized price	**$ 80.71**	$ 89.56	$ 86.73	**$ (8.85)**	$ 2.83
NGL (per bbl)					
Average field-level price	**$ 32.95**	$ 39.95	$ 34.43	**$ (7.00)**	$ 5.52
Commodity derivative impact	**—**	—	1.90	**—**	(1.90)
Net realized price	**$ 32.95**	$ 39.95	$ 36.33	**$ (7.00)**	$ 3.62
Average net equivalent price (per Mcfe)					
Average field-level price	**$ 7.34**	$ 6.11	$ 4.34	$ 1.23	$ 1.77
Commodity derivative impact	**(0.01)**	0.48	1.14	(0.49)	(0.66)
Net realized price	**$ 7.33**	$ 6.59	$ 5.48	$ 0.74	$ 1.11

Revenue, Volume and Price Variance Analysis

The following table shows volume and price related changes for each of QEP Energy's major revenue components for the year ended December 31, 2014 compared to the years ended December 31, 2013 and 2012:

	Gas	**Oil**	**NGL**	**Total**
	(in millions)			
QEP Energy Production Revenues				
Year ended December 31, 2012 revenues	$ 667.4	$ 532.6	$ 184.2	$ 1,384.2
Changes associated with volumes [(1)]	(81.5)	329.6	(18.5)	229.6
Changes associated with prices [(2)]	193.1	54.4	26.5	274.0
Year ended December 31, 2013 revenues	$ 779.0	$ 916.6	$ 192.2	$ 1,887.8
Changes associated with volumes [(1)]	**(140.6)**	**622.8**	**78.2**	**560.4**
Changes associated with prices [(2)]	**138.0**	**(171.2)**	**(47.3)**	**(80.5)**
Year ended December 31, 2014 revenues	**$ 776.4**	**$ 1,368.2**	**$ 223.1**	**$ 2,367.7**

(1) The revenue variance attributed to the change in volume is calculated by multiplying the change in volumes from the years ended December 31, 2014 and 2013, as compared to the years ended December 31, 2013 and 2012, by the average field-level price for the years ended December 31, 2013 and 2012.

(2) The revenue variance attributed to the change in price is calculated by multiplying the change in field-level prices from the years ended December 31, 2014 and 2013, as compared to the years ended December 31, 2013 and 2012, by the respective volumes for the years ended December 31, 2013 and 2012. Pricing changes are driven by changes in commodity field-level prices, excluding the impact from commodity derivatives.

December 31, 2014 compared to December 31, 2013

Gas sales. Gas sales were $776.4 million for the year ended December 31, 2014, a decrease of $2.6 million, or 0.3%, compared to 2013. This decrease was a result of an 18% decrease in gas production, partially offset by higher average field-level gas prices. The decrease in production volumes was primarily driven by the continued suspension of QEP's Haynesville/Cotton Valley operated drilling program and a production decrease due to the divestitures of the Company's Midcontinent properties at the end of the second quarter of 2014. Additionally, production decreased at QEP's Pinedale field due to ethane recovery in 2014, in which ethane is extracted from the gas stream and sold as an NGL, compared to ethane rejection in 2013, in which ethane is sold in the gas stream. Average field-level gas prices increased 22% in 2014 compared to 2013, driven by an increase in average NYMEX-HH natural gas prices for the comparable periods.

Oil sales. Oil sales were $1,368.2 million for the year ended December 31, 2014, an increase of $451.6 million, or 49%, compared to 2013. This increase was a result of a 68% increase in oil production, partially offset by an 11% decrease in average field-level oil prices. The increase in production volumes was primarily driven by increases in the Williston Basin due to ongoing development of the properties acquired in the Williston Basin Acquisition. The Company also had an additional 1,582.2 Mbbls of production in 2014 from its Permian Basin Acquisition. These volume increases were partially offset by a decrease from the divestitures of the Company's Midcontinent properties at the end of the second quarter of 2014. Average field-level oil prices decreased 11% in 2014 compared to 2013, driven by a decrease in average NYMEX-WTI and ICE Brent oil prices for the comparable periods.

NGL Sales. NGL sales were $223.1 million for the year ended December 31, 2014, an increase of $30.9 million, or 16%, compared to 2013. This increase was primarily a result of a 41% increase in NGL production, partially offset by an 18% decrease in average field-level NGL prices. NGL production increased by 41% from 4,811.3 Mbbl in 2013 to 6,769.1 Mbbl in 2014, due primarily to increased volumes in Pinedale and Uinta due to ethane recovery in 2014 compared to ethane rejection in 2013, while the Williston Basin NGL volumes grew as a result of increased development drilling. Additionally, the Permian Basin Acquisition contributed to the increased NGL production. These volume increases were partially offset by a decrease due to the divestitures of the Company's Midcontinent properties in the second quarter of 2014. NGL prices decreased in 2014 primarily as a result of partially recovering ethane from the gas stream in Pinedale and Uinta during 2014, compared to ethane rejection in 2013. Ethane generally receives a lower per barrel price than other NGL components resulting in a lower average NGL price per barrel.

December 31, 2013 compared to December 31, 2012

Gas sales. Gas sales were $779.0 million for the year ended December 31, 2013, an increase of $111.6 million, or 17%, compared to 2012. This increase was a result of 33% higher average field-level gas prices partially offset by a 12% decrease in gas production. The decrease in production volumes was driven by the suspension of QEP's Haynesville/Cotton Valley operated drilling program in July 2012, partially offset by increased production from its drilling programs in Pinedale, the Midcontinent, Uinta Basin and Williston Basin. Gas field-level prices increased as a result of increased demand.

Oil sales. Oil sales were $916.6 million for the year ended December 31, 2013, an increase of $384.0 million, or 72%, compared to 2012. This increase was a result of a 62% increase in oil production and 6% increase in average field level oil prices. The increase in production was the result of production related to the Williston Basin Acquisition and QEP's development drilling program. Field-level oil prices increased in 2013 due to improved pricing for Williston Basin oil volumes despite a decrease in Brent oil prices and only a slight increase in WTI oil prices.

NGL Sales. NGL sales were $192.2 million for the year ended December 31, 2013, an increase of $8.0 million, or 4%, compared to 2012. This increase was primarily a result of a 16% increase in average field-level NGL prices partially offset by decreased NGL production. NGL production decreased by 10% from 5,349.0 Mbbl in 2012 to 4,811.3 Mbbl in December 31, 2013 as a result of not recovering ethane from its wet gas production stream in the first three quarters of 2013. When ethane is sold as part of the gas stream instead of being recovered as a NGL, the average NGL barrel sales price increases as the price of the remaining NGL components are higher than the ethane price.

QEP Energy Resale Margin

QEP Energy purchases and resells gas in order to fulfill firm transportation contract commitments and to partially mitigate potential losses on unfilled capacity. The difference between the price of the products purchased and sold, net of transportation costs, creates a resale margin that represents a gain or loss for the Company. The following table is a summary of QEP Energy's financial results from its gas resale activities:

Resale Margin	Year Ended December 31, 2014	2013	2012	Change 2014 vs 2013	2013 vs 2012
	(in millions)				
Purchased gas sales	**$ 150.0**	$ 191.6	$ 222.0	**$ (41.6)**	$ (30.4)
Purchased gas expense	**150.0**	197.1	224.7	**(47.1)**	(27.6)
Resale margin (loss) gain	**$ —**	$ (5.5)	$ (2.7)	**$ 5.5**	$ (2.8)

During the year ended December 31, 2014, QEP recognized no gain or loss on resale margin. During the years ended December 31, 2013 and 2012, QEP Energy recorded a loss on resale margin of $5.5 million and $2.7 million, respectively, as a result of pipeline transportation commitments in Louisiana.

Operating Expenses

The following table presents certain QEP Energy operating expenses on a unit of production basis:

	Year Ended December 31, 2014	2013	2012	Change 2014 vs 2013	2013 vs 2012
	(per Mcfe)				
Depreciation, depletion and amortization	**$ 3.05**	$ 3.09	$ 2.63	**$ (0.04)**	$ 0.46
Lease operating expense	**0.74**	0.59	0.55	**0.15**	0.04
Gas, oil and NGL transportation and other handling costs	**0.90**	0.78	0.71	**0.12**	0.07
Production taxes	**0.63**	0.51	0.30	**0.12**	0.21
Total Operating Expenses	**$ 5.32**	$ 4.97	$ 4.19	**$ 0.35**	$ 0.78

December 31, 2014 compared to December 31, 2013

Depreciation, depletion and amortization (DD&A). QEP Energy's DD&A expense increased $30.2 million, but decreased $0.04 per Mcfe, during the year ended December 31, 2014 compared to 2013. The increase in DD&A expense was due to expense increases in the Williston Basin, Pinedale and related to the Permian Basin Acquisition, partially offset by expense decreases in the Midcontinent and Haynesville/Cotton Valley. The increase in the Williston Basin expense relates to increased production while the increase in Pinedale primarily relates to an increased DD&A rate. The decrease in the Midcontinent DD&A expense was a result of the second and fourth quarters 2014 property sales (see Note 2 - Acquisitions and Divestitures)while the decrease in expense in Haynesville/Cotton Valley relates to declining production.

Lease operating expense. The following table presents lease operating expense (LOE) for QEP Energy by region on a unit of production basis:

	Year Ended December 31, 2014	2013	Change 2014 vs 2013
Northern Region	**$ 0.63**	$ 0.60	**$ 0.03**
Southern Region	**0.90**	0.57	**0.33**
Average production cost	**0.74**	0.59	**0.15**

QEP Energy's LOE increased $58.8 million, or $0.15 per Mcfe, during the year ended December 31, 2014 compared to 2013. The Southern Region's LOE per Mcfe increase during 2014 was driven primarily by the Permian Basin Acquisition oil wells in the first quarter of 2014, which is a new operating area for QEP where we have experienced higher costs and a per Mcfe increase in Haynesville/Cotton Valley. The Haynesville increase is due to declining production volume but relatively flat labor costs, and other fixed operating expenses due to the consistent well count and increased workover costs. The Northern Region increase was driven primarily by increased well count and greater production from the Williston Basin oil wells, which have higher operating costs compared to the other properties, which are primarily lower cost gas wells.

Gas, oil, and NGL transportation and other handling costs. QEP Energy's gas, oil and NGL transportation and other handling costs increased $49.3 million, or $0.12 per Mcfe, during the year ended December 31, 2014, due to increased production in the Williston Basin and additional expenses associated with the properties in the Permian Basin Acquisition.

Production and property taxes. In most states in which QEP Energy operates, QEP pays production taxes based on a percentage of field-level revenue, except in Louisiana, where severance taxes are volume based. Production and property taxes increased $44.2 million, or $0.12 per Mcfe, during 2014, as a result of increased oil and NGL revenues due to increased production.

Exploration expense. Exploration expense decreased $2.0 million during the year ended December 31, 2014, for QEP Energy. The decrease primarily related to lower exploration-related labor.

Impairment expense. During the year ended December 31, 2014, QEP Energy recorded impairment charges of $1,143.2 million. Of the $1,143.2 million impairment charges during 2014, $1,041.4 million related to the impairment charge on proved properties in QEP's Haynesville/Cotton Valley and Permian Basin due to lower future prices and $101.8 million related to impairment on unproved properties primarily in QEP's Haynesville/Cotton Valley due to lower future prices, expiration of primary lease terms and changes in drilling plans. Oil and gas properties and leaseholds in the Southern Region accounted for $1,116.8 million of the $1,143.2 million impairment charges during 2014, and $26.4 million related to oil and gas properties and leaseholds in the Northern Region.

December 31, 2013 compared to December 31, 2012

Depreciation, depletion and amortization. QEP Energy's DD&A expense increased $115.8 million, or $0.46 per Mcfe, during the year ended December 31, 2013 when compared to 2012. The increase in DD&A expense per Mcfe was primarily a result of increased DD&A rates in the Williston Basin and Haynesville/Cotton Valley, partially offset by lower DD&A rates in the Uinta Basin. The increase in the Williston Basin rate is due to the additional proved costs recorded as part of the Williston Basin Acquisition, while the increase in the Haynesville/Cotton Valley rate was due to a year-end 2012 negative revision of proved undeveloped reserves as a result of lower gas prices. These increases were partially offset by a decrease in the Uinta Basin rate due to a 2012 proved property impairment and the addition of proved undeveloped reserves recorded at year-end 2012.

Lease operating expense. The following table presents LOE for QEP Energy by region on a unit of production basis:

	Year Ended December 31,		Change
	2013	2012	2013 vs 2012
Northern Region	$ 0.60	$ 0.63	$ (0.03)
Southern Region	0.57	0.47	0.10
Average production cost	$ 0.59	$ 0.55	$ 0.04

LOE increased $5.5 million, or $0.04 per Mcfe, during the year ended December 31, 2013 compared to 2012. The Southern Region's LOE per Mcfe increase during 2013 was driven by declining production volume in the Haynesville/Cotton Valley properties despite relatively flat labor and pumper costs, fixed operating expenses due to the slight increase in total well count and increased repairs and maintenance costs. The Northern Region decrease was driven primarily by a per Mcfe decrease in the Williston Basin due to cost efficiencies in the current year attributable to the Williston Basin Acquisition.

Gas, oil, and NGL transportation and other handling costs. QEP Energy's gas, oil and NGL transportation and other handling costs increased $14.1 million, or $0.07 per Mcfe, during the year ended December 31, 2013, due to cost increases in the Midcontinent, Haynesville/Cotton Valley field and the Williston Basin. The Midcontinent transportation and other handling costs per Mcfe increased 38% due to revised rate calculation methodology. Haynesville/Cotton Valley transportation and other handling costs per Mcfe increased 27% due to firm transportation commitments and declining production volumes. Transportation and other handling costs per Mcfe in the Williston Basin increased 16% due to increased gathering costs associated with the properties from the Williston Basin Acquisition.

Production and property taxes. In most states in which QEP Energy operates, QEP pays production taxes based on a percentage of field-level revenue, except in Louisiana, where severance taxes are volume based. Production and property taxes increased $62.6 million, or $0.21 per Mcfe, during 2013, as a result of increased gas, oil and NGL revenues due to higher field-level gas, oil and NGL prices, higher oil production and a larger percentage of production coming from North Dakota, which has a higher average production tax rate.

Exploration expense. Exploration expenses increased $0.7 million during the year ended December 31, 2013, for QEP Energy. The increase primarily related to increases in exploration-related labor.

Impairment expense. During the year ended December 31, 2013, QEP Energy recorded impairment charges of $93.0 million. Of the $93.0 million impairment charges during 2013, $1.2 million related to the impairment charge on proved properties, $32.3 million related to impairment on unproved properties due to expiration of primary lease terms and changes in drilling plans and $59.5 million related to impairment of goodwill (refer to Note 1 - Summary of Significant Accounting Policies, in Item 8 of Part II of this Annual Report on Form 10-K for detailed information on goodwill). Oil and gas properties and leaseholds in the Southern Region accounted for $17.5 million of the $93.0 million impairment charges during 2013, and $16.0 million related to oil and gas properties and leaseholds in the Northern Region.

QEP Marketing and Other

QEP Marketing and Other includes the results of operations from QEP Marketing, the retained interest in the Haynesville Gathering System and corporate functions. The following table provides a summary of QEP Marketing and Other's financial and operating results:

	Year Ended December 31,			Change	
	2014	2013	2012	**2014 vs 2013**	2013 vs 2012
			(in millions)		
Revenues					
Purchased gas, oil and NGL sales	**$ 2,360.6**	$ 1,567.4	$ 1,013.1	**$ 793.2**	$ 554.3
Other	**21.7**	33.8	54.4	**(12.1)**	(20.6)
Total Revenues	**2,382.3**	1,601.2	1,067.5	**781.1**	533.7
Operating expenses					
Purchased gas, oil and NGL expense	**2,356.6**	1,570.5	1,021.1	**786.1**	549.4
Gathering and other expense	**6.8**	8.4	8.2	**(1.6)**	0.2
General and administrative	**6.3**	4.4	1.7	**1.9**	2.7
Production and property taxes	**1.2**	1.5	1.3	**(0.3)**	0.2
Depreciation, depletion and amortization	**10.3**	9.6	11.8	**0.7**	(2.2)
Total Operating Expenses	**2,381.2**	1,594.4	1,044.1	**786.8**	550.3
Net gains (losses) from asset sales	**—**	(0.6)	—	**0.6**	(0.6)
Operating income (loss)	**1.1**	6.2	23.4	**(5.1)**	(17.2)
Realized gains (losses) on derivative instruments	**(10.1)**	(2.2)	3.8	**(7.9)**	(6.0)
Unrealized gains (losses) on derivative instruments	**6.2**	2.0	(5.2)	**4.2**	7.2
Interest and other income	**209.7**	206.9	132.3	**2.8**	74.6
Loss on extinguishment of debt	**(2.0)**	—	(0.6)	**(2.0)**	0.6
Interest expense	**(167.5)**	(167.8)	(133.0)	**0.3**	(34.8)
Income (loss) from continuing operations before income taxes	**37.4**	45.1	20.7	**(7.7)**	24.4
Income tax (provision) benefit	**(14.4)**	(18.6)	(10.2)	**4.2**	(8.4)
Net income (loss) from continuing operations	**$ 23.0**	$ 26.5	$ 10.5	**$ (3.5)**	$ 16.0

Resale Margin

The following table is a summary of QEP's Marketing's financial results from resale activities:

	Year Ended December 31,			Change	
	2014	2013	2012	**2014 vs 2013**	2013 vs 2012
Purchased gas, oil and NGL sales	**$ 2,360.6**	$ 1,567.4	$ 1,013.1	**$ 793.2**	$ 554.3
Purchased gas, oil and NGL expense	**(2,356.6)**	(1,570.5)	(1,021.1)	**(786.1)**	(549.4)
Realized gains (losses) on derivative instruments	**(10.1)**	(2.2)	3.8	**(7.9)**	(6.0)
Resale margin loss	**$ (6.1)**	$ (5.3)	$ (4.2)	**$ (0.8)**	$ (1.1)

During the years ended December 31, 2014, 2013 and 2012, QEP Marketing's loss on resale margin was primarily the result of the fulfillment of firm transportation contract commitments, resulting in firm transportation expenses. Purchased gas, oil and NGL sales increased by $793.2 million, or 51%, during the year ended December 31, 2014 compared to 2013, due to a $765.4 million increase in resale oil and NGL sales and a $27.8 million increase in resale gas sales. Resale oil and NGL sales increased due to a 107% increase in the resale oil and NGL volumes, partially offset by a 14% decrease in resale oil and NGL price. Resale gas sales increased due to a 47% increase in resale price, partially offset by 29% decrease in resale volumes.

During the year ended December 31, 2014, purchased gas, oil and NGL expense, which includes transportation expense, increased 50% compared to the year ended December 31, 2013, due to a $765.0 million increase in resale oil and NGL purchases and a $21.1 million increase in resale gas purchases. Resale oil and NGL sales increased due to a 108% increase in resale purchase volumes, partially offset by a 12% decrease in resale purchase price. Resale gas purchases increased due to a 21% increase in the resale purchase price, partially offset by 13% decrease in resale purchase gas volumes.

During the year ended December 31, 2013, purchased gas, oil and NGL sales increased by $554.3 million, or 55%, compared to the year ended December 31, 2012, due to a $133.7 million increase in resale gas sales and a $420.6 million increase in resale oil and NGL sales. Resale gas sales increased due to a 33% increase in the resale price partially offset by a 3% decrease in resale gas volumes. Resale oil and NGL sales increased due to a 9% increase in resale price and a 61% increase in resale volumes.

During the year ended December 31, 2013, purchased gas, oil and NGL expense, which includes transportation expense, increased $549.4 million, or 54%, compared to the year ended December 31, 2012, due to a $131.4 million increase in resale gas purchases and a $420.2 million increase in resale oil and NGL purchases. Resale gas purchases increased due to a 36% increase in the resale purchase price, whereas resale purchase volumes decreased 7% period to period. Resale oil and NGL sales increased due to a 62% increase in resale purchase volumes and a 9% increase in resale purchase price.

QEP Resources

Other Consolidated Expenses and Income from Continuing and Discontinued Operations

December 31, 2014 compared to December 31, 2013

General and Administrative. During 2014, general and administrative (G&A) expense increased $44.0 million, or 27%, compared to 2013. The increase in G&A in 2014, compared to 2013, was primarily due to the following: a $22.7 million increase in labor and benefits associated with increases in the number of employees before completion of the Midstream Sale and the Company's annual compensation program and an $11.1 million increase in professional and outside services and compensation expense mainly related to the Enterprise Resource Planning (ERP) system implementation.

Net gain (loss) from asset sales. During the year ended December 31, 2014, QEP recognized a loss on sale of assets of $148.6 million, compared to a gain on sale of $103.5 million during the year ended December 31, 2013. The loss on sale of assets recognized in 2014 is primarily due to QEP Energy's divestitures of the majority of the Company's Midcontinent properties in the second and fourth quarters of 2014 for a pre-tax loss on sale of $146.1 million.

Realized and unrealized gains (losses) on derivative contracts. Gains and losses on derivative instruments are comprised of both realized and unrealized gains and losses on QEP's commodity derivative contracts and interest rate swaps, which are marked-to-market each month. During the year ended December 31, 2014, gains on commodity derivative instruments were $368.9 million, of which $3.5 million was realized losses and $372.4 million was unrealized gains. Additionally, during the year ended December 31, 2014, losses from interest rate swaps were $5.6 million, of which $7.6 million was realized losses partially offset by $2.0 million in unrealized gains. During 2013, gains on commodity derivative instruments were $57.5 million, of which $150.3 million was realized partially offset by $92.8 million in unrealized losses. Additionally, during 2013, gains from interest rate swaps were $1.4 million, of which $2.7 million was realized losses offset by $4.1 million in unrealized gains.

Interest expense. Interest expense increased $4.0 million, or 2%, during the year ended December 31, 2014, compared to 2013, due to higher average debt levels in 2014. The increase in debt levels in 2014 was primarily related to additional borrowing on the credit facility and an increase in QEP's term loan to $600.0 million in the first quarter of 2014, both of which were used to fund the Permian Basin Acquisition. In December 2014, QEP repaid and terminated its $600.0 million term loan and repaid the entire outstanding balance on the credit facility with a portion of the proceeds from the Midstream Sale.

Income taxes. Income tax provision decreased $292.6 million during the year ended December 31, 2014 compared to 2013. The decrease was the result of lower income before income taxes and a lower combined effective federal and state income tax rate of 36.2% during the year ended December 31, 2014, compared to 53.6% for the year ended December 31, 2013. The 2013 combined effective rate was higher due to the impairment of goodwill of $59.5 million that is non-deductible for tax purposes.

Discontinued Operations. Discontinued operations represent results of operations from QEP Field Services, excluding the results of the Haynesville Gathering System, which was retained by QEP Marketing. During the year ended December 31, 2014, net income from discontinued operations was $1,193.9 million, which includes a $1,793.4 million gain on sale. Excluding the gain on sale, income before taxes from discontinued operations decreased $48.7 million during the year ended December 31, 2014, compared to 2013. This decrease was primarily due to only having 11 months of activity in 2014 compared to a full year of activity in 2013 and an 8% decrease in QEP Field Services' keep-whole margin during the year ended December 31, 2014. The decrease in keep-whole margin was due to an increase in transportation and shrink expenses primarily related to higher natural gas prices, partially offset by a 7% increase in NGL sales due to a 20% increase in the average net realized NGL sales price. The increase in the NGL sales price was a result of higher propane prices in the first half of 2014 compared to the first half of 2013 and the completion of the Blacks Fork fractionation and loading facility expansion in late 2013, which gave QEP Field Services the ability to sell products into local and regional markets.

December 31, 2013 compared to December 31, 2012

General and Administrative. General and administrative expenses decreased by $88.0 million, or 35%, during the year ended December 31, 2013 compared to 2012. The decrease in G&A expenses for 2013 was primarily due to a $115.0 million litigation loss contingency recognized during 2012 as well as a $6.1 million decrease in restructuring costs and a $2.7 million decrease in the mark-to-market value of the Deferred Compensation Wrap Plan and Cash Incentive Plan. These decreases were partially offset by a $16.9 million increase in labor costs due to the increased number of employees and the Company's annual compensation program and a $24.8 million increase in professional and outside services including the ongoing implementation of a new Enterprise Resource Planning system, legal costs, feasibility studies, software maintenance costs and other contracted or professional services.

Net gain (loss) from asset sales. During the year ended December 31, 2013, QEP Energy sold its interest in several non-core oil and gas properties for total cash proceeds of $205.8 million and a pre-tax gain on sale of $105.7 million.

Realized and unrealized gains (losses) on derivative contracts. Gains and losses on derivative instruments are comprised of both realized and unrealized gains and losses on QEP's commodity derivative contracts and interest rate swaps, which are marked-to-market each month. During the year ended December 31, 2013, gains on commodity derivative instruments were $57.5 million, of which $150.3 million was realized gains and $92.8 million was unrealized losses. Additionally, during the year ended December 31, 2013, gains from interest rate swaps were $1.4 million, of which $2.7 million was realized losses offset by $4.1 million in unrealized gains. During 2012, gains on commodity derivative instruments were $440.9 million, of which $371.6 million was realized and $69.3 million was unrealized. Additionally, during 2012, losses from interest rate swaps were $7.4 million, of which $1.3 million was realized and $6.1 million was unrealized.

Interest expense. Interest expense increased $38.8 million, or 31%, during the year ended December 31, 2013, compared to 2012. The increase was attributable to average debt levels that were approximately $656.3 million, or 27%, higher than average debt levels in 2012. The increase in average debt levels is primarily related to the issuance of the $650.0 million of 2023 senior notes in the third quarter of 2012, which was used to fund the Williston Basin Acquisition, partially offset by a lower balance under our revolving credit facility after repayment of the revolving credit facility in 2013 with the net proceeds provided by QEP Midstream's initial public offering.

Income taxes. Income tax provision increased $62.0 million during the year ended December 31, 2013, compared to 2012. The increase was primarily the result of higher income before income taxes and a higher combined effective federal and state income tax rate of 53.6% during the year ended December 31, 2013, due to the impairment of goodwill of $59.5 million that is non-deductible for tax purposes.

Discontinued Operations. Discontinued operations represent results of operations from QEP Field Services, excluding the results of the Haynesville Gathering System. During the years ended December 31, 2013 and 2012, net income from discontinued operations was $107.3 million and $125.9 million, respectively. The decrease in net income was primarily due to decreased NGL sales and decreased gathering revenue. The decreased NGL sales volumes was a result of QEP Field Services not recovering ethane on its keep-whole volumes. The decrease in gathering revenues was a result of lower volumes at QEP Field Services' Blacks Fork hub due to higher volumes being gathered under a contract that had a lower rate.

LIQUIDITY AND CAPITAL RESOURCES

QEP seeks to fund its development projects by employing a capital structure and financing strategy to provide sufficient liquidity to withstand commodity price swings. QEP maintains a commodity price derivative strategy to reduce commodity price volatility and to provide some certainty to cash flows. QEP funds its operations, capital expenditures and working capital requirements with cash flow from its operating activities and borrowings under its credit facilities. Periodically, QEP accesses debt and equity capital markets and sells assets to provide additional liquidity. The Company believes cash flow from operations, cash-on-hand and availability under its credit facility will be sufficient to fund the Company’s planned capital expenditures and operating expenses during the next 12 months and the foreseeable future. To the extent actual operating results differ from the Company’s estimates, QEP's liquidity could be adversely affected.

The following table provides QEP’s available liquidity and debt to equity ratio compared to the previous period:

	December 31,	
	2014	2013
	(in millions, except %)	
Cash and cash equivalents	**$ 1,160.1**	$ 11.9
Amount available under the QEP credit facility [1]	**1,796.3**	1,016.2
Total liquidity	**$ 2,956.4**	$ 1,028.1
Total debt	**$ 2,218.1**	$ 2,997.5
Total common shareholders' equity	**4,075.3**	3,376.6
Ratio of debt to total capital [2]	**35%**	47%

(1) See discussion of revolving credit facility below. Availability under the QEP credit facility is reduced by outstanding letters of credit of $3.7 million and $3.8 million as of December 31, 2014 and 2013, respectively.

(2) Defined as total debt divided by the sum of total debt plus common shareholders’ equity.

QEP's Credit Facility

QEP’s unsecured revolving credit facility, which matures in December 2019, provides for loan commitments of $1.8 billion from a group of financial institutions. The credit facility provides for borrowings at short-term interest rates and contains customary covenants and restrictions.

On December 2, 2014, QEP entered into the Fourth Amendment to its Credit Agreement, which increased the aggregate principal amount of commitments to $1.8 billion, extended the maturity date to December 2, 2019, and made minor adjustments to other provisions and covenants.

During the years ended December 31, 2014 and 2013, QEP's weighted-average interest rates on borrowings from its credit facility were 2.23% and 2.22%, respectively. At December 31, 2014, QEP had no borrowings outstanding and had $3.7 million in letters of credit outstanding under the credit facility. At December 31, 2013, QEP had $480.0 million outstanding and QEP had $3.8 million in letters of credit outstanding under the credit facility. At February 20, 2015, QEP had no borrowings outstanding and had $3.7 million of letters of credit issued under the credit facility. At December 31, 2014 and 2013, QEP was in compliance with the covenants under the credit facility.

Term Loan

On December 2, 2014, QEP repaid and terminated its $600.0 million term loan with a portion of the proceeds from the Midstream Sale. The term loan facility provided borrowings at short-term interest rates and contained covenants, restrictions and interest rates that were substantially the same as QEP’s revolving credit facility. During the years ended December 31, 2014 and 2013, QEP's weighted-average interest rates on borrowings from the term loan were 2.28% and 2.22%, respectively.

Senior Notes

The Company's senior unsecured notes outstanding as of December 31, 2014, totaled $2,221.8 million principal amount and are comprised of six issuances as follows:

- $176.8 million 6.05% Senior Notes due September 2016;
- $134.0 million 6.80% Senior Notes due April 2018;
- $136.0 million 6.80% Senior Notes due March 2020;
- $625.0 million 6.875% Senior Notes due March 2021;
- $500.0 million 5.375% Senior Notes due October 2022; and
- $650.0 million 5.25% Senior Notes due May 2023.

Cash Flow from Operating Activities

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

Net cash provided by operating activities during the year ended December 31, 2014, increased $350.8 million compared to 2013, due to an increase in net income and changes in operating assets and liabilities, partially offset by non-cash adjustments to net income. Changes in operating assets and liabilities increased $789.6 million during the year ended December 31, 2014, mainly due to a $521.5 million increase in income taxes payable primarily related to the recognition of the gain on the Midstream Sale and an increase of $499.8 million in accounts payable and accrued expenses partially offset by a decrease in accounts receivable of $163.7 million both of which were primarily related to timing of payments and receipts. Non-cash adjustments to net income decreased $1,073.4 million due to the $1,793.4 million gain on the Midstream Sale and unrealized gains on derivative contracts during 2014 of $374.4 million compared to $88.7 million of losses in 2013 both of which were partially offset by a $1,050.2 million increase in impairment expense during 2014.

Net cash provided by operating activities during the year ended December 31, 2013, decreased $104.3 million compared to 2012, due to changes in operating assets and liabilities partially offset by an increase in net income and non-cash adjustments to net income. Changes in operating assets and liabilities used $176.1 million of cash during the year ended December 31, 2013, mainly due to a decrease in accounts payable and accrued expenses primarily due to the $115.0 million lawsuit settlement payment in the first quarter of 2013 and an increase in deferred income taxes.

Net cash provided from operating activities is presented below:

	Year Ended December 31,			Change	
	2014	2013	2012	**2014 vs 2013**	2013 vs 2012
			(in millions)		
Net income attributable to QEP	**$ 784.4**	$ 159.4	$ 128.3	**$ 625.0**	$ 31.1
Net income attributable to noncontrolling interest	**21.6**	12.0	3.7	**9.6**	8.3
Non-cash adjustments to net income	**123.0**	1,196.4	1,038.0	**(1,073.4)**	158.4
Changes in operating assets and liabilities	**613.5**	(176.1)	126.0	**789.6**	(302.1)
Net cash provided from operating activities	**$ 1,542.5**	$ 1,191.7	$ 1,296.0	**$ 350.8**	$ (104.3)

Cash Flow from Investing Activities

During the year ended December 31, 2014, net cash provided by investing activities was $578.2 million compared to net cash used in investing activities of $1,441.5 million in 2013. The increase in cash provided by investing activities was primarily due to proceeds from the Midstream Sale of approximately $2.5 billion, proceeds from the sales of non-core oil and gas properties of $787.8 million, partially offset by the Permian Basin Acquisition, which closed in the first quarter of 2014 for a total purchase price of $941.8 million and increased capital expenditures of approximately $1,123.8 million.

During the year ended December 31, 2013, net cash used in investing activities was $1,441.5 million compared to $2,794.5 million during the year ended December 31, 2012. This decrease in investing activities was primarily due to the Williston Basin Acquisition in which the Company spent approximately $1.4 billion and the proceeds of $205.8 million from QEP Energy's 2013 property divestitures. These items that resulted in a decrease in cash used in investing activities were partially offset by an increase in cash capital expenditures from QEP's Energy's drilling programs.

A comparison of capital expenditures for the years ended December 31, 2014, 2013 and 2012, and a forecast for the calendar year 2015 are presented in the table below:

	2015 Forecast[(1)]	Year Ended December 31,			Change	
		2014	2013	2012	**2014 vs 2013**	2013 vs 2012
		(in millions)				
QEP Energy	$ 960.0	**$ 2,670.5**	$ 1,467.2	$ 2,702.4	**$ 1,203.3**	$ (1,235.2)
QEP Marketing and Other	15.0	**13.6**	24.6	21.6	**(11.0)**	3.0
Continuing Operations	975.0	**2,684.1**	1,491.8	2,724.0	**1,192.3**	(1,232.2)
Discontinued Operations	—	**50.7**	85.6	164.2	**(34.9)**	(78.6)
Total accrued capital expenditures	975.0	**2,734.8**	1,577.4	2,888.2	**1,157.4**	(1,310.8)
Change in accruals	—	**(8.4)**	25.2	(88.5)	**(33.6)**	113.7
Total cash capital expenditures	$ 975.0	**$ 2,726.4**	$ 1,602.6	$ 2,799.7	**$ 1,123.8**	$ (1,197.1)

(1) Represents the mid-point end of the most recent guidance.

During the year ended December 31, 2014, capital expenditures on a cash basis increased 70% to $2,726.4 million, compared to $1,602.6 million during the year ended December 31, 2013. The increase of $1,123.8 million cash capital expenditures during 2014 was primarily the result of QEP Energy's increased capital expenditures related to the Permian Basin Acquisition.

QEP Energy's capital investment, on an accrual basis, during the year ended December 31, 2014, increased $1,203.3 million compared to 2013. This increase was primarily due to the Permian Basin Acquisition, which closed during the first quarter of 2014 for a total purchase price of $941.8 million. In addition, capital expenditures increased $36.9 million in the Williston Basin and $375.6 million in the Permian Basin due to additional drilling activity and operations in those areas. These increases were partially offset by decreases of $216.2 million in the Midcontinent due to decreased drilling and operations following divestitures of non-core properties and $34.1 million in the Uinta Basin due to a decreased rig count.

During the year ended December 31, 2013, capital expenditures on a cash basis decreased 43% to $1,602.6 million, compared to $2,799.7 million during the year ended December 31, 2012. The decrease of $1,197.1 million cash capital expenditures during 2013 was primarily the result of lower QEP Energy capital expenditures in 2013 due to the $1,406.1 million spent in 2012 on the Williston Basin Acquisition.

QEP Energy's capital investment, on an accrual basis, during the year ended December 31, 2013, decreased $1,235.2 million compared to 2012. QEP Energy's capital expenditures include $36.9 million related to property acquisitions in the Williston Basin and $4.0 million of post-closing adjustments for the Williston Basin Acquisition incurred during 2013, compared to $1,406.1 million of property acquisitions in 2012 related to the Williston Basin Acquisition. In addition, capital expenditures increased $398.2 million in the Williston Basin due to additional drilling activity and operations in the area, partially offset by a $57.2 million decrease in the Haynesville/Cotton Valley area due to the suspended drilling program, a $109.8 million decrease in Pinedale due to the reduction in the number of drilling rigs from six throughout the majority of 2012 to four during 2013 and wells drilled by QEP in Pinedale, in which QEP has no working interest, and a $33.8 million decrease in Midcontinent capital expenditures due to reduced drilling activity.

At December 31, 2014, the midpoint of our forecasted capital investment for 2015 is $975.0 million, comprised of $960.0 million allocated to QEP Energy and $15.0 million between QEP Marketing and Other. QEP intends to fund capital expenditures with cash flow from operating activities, and, if needed, borrowings under its revolving credit facility. As a result of the decline in oil and gas prices, forecasted capital investment is expected to be significantly lower than in 2014. QEP plans minimal capital expenditures for the Haynesville Shale and other dry-gas development areas in 2015 and plans to focus investment during 2015 on higher return projects, including oil-directed horizontal drilling in the Williston Basin and the Permian Basin. QEP Energy has allocated approximately 96% of its forecasted 2015 drilling and completion capital expenditure budget to oil and liquids-rich gas plays. QEP plans to invest approximately $15.0 million in capital expenditures related to corporate activities. The aggregate levels of capital expenditures for 2015 and the allocation of those expenditures are dependent on a variety of factors, including drilling results, gas, oil and NGL prices, industry conditions, the extent to which properties or working interests are acquired, the availability of capital resources to fund the expenditures and changes in management's business assessments as to where QEP's capital can be most profitably deployed. Accordingly, the actual levels of capital expenditures and the allocation of those expenditures may vary materially from QEP's estimates.

Cash Flow from Financing Activities

During the year ended December 31, 2014, net cash used in financing activities was $990.6 million compared to net cash provided by financing activities of $279.8 million during the year ended December 31, 2013. During the year ended December 31, 2014, QEP had borrowings from the credit facility of $5,455.0 million and borrowings under the term loan of $300.0 million, which were used to fund the Permian Basin Acquisition and operating activities throughout the year. During the year ended December 31, 2014, QEP had repayments on its credit facility of $5,935.0 million and repayments on its term loan of $600.0 million, which were primarily funded from the Midstream Sale and other non-core asset divestitures. Additionally, during the year ended December 31, 2014, there was a decrease in the checks outstanding in excess of cash balances of $54.4 million and $99.7 million of cash was used to repurchase common stock, which was retired under the Company's share repurchase plan. At December 31, 2014, long-term debt consisted of $2,221.8 million in senior notes (excluding $3.7 million of net original issue discount).

During the year ended December 31, 2013, net cash proceeds from financing activities was $261.7 million compared to $1,498.5 million during the year ended December 31, 2012. During the year ended December 31, 2013, QEP had borrowings from the credit facility of $3,085.0 million and repayments on the credit facility of $3,295.0 million, partially funded by the net proceeds provided from QEP Midstream's initial public offering, partially offset by increases to the checks outstanding in excess of cash balances of $51.2 million. During the year ended December 31, 2013 and 2012, QEP paid $14.3 million and $14.2 million, respectively, of regular quarterly dividends. At December 31, 2013, long-term debt consisted of $480.0 million outstanding under its credit facility, $300.0 million under the Term Loan and $2,221.8 million in senior notes (excluding $4.3 million of net original issue discount).

Off-Balance Sheet Arrangements

QEP may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. At December 31, 2014, the Company's material off-balance sheet arrangements and transactions included operating lease arrangements, drilling and transportation contracts and undrawn letters of credit. There are no other transactions, arrangements, or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect QEP's liquidity or availability of, or requirements for capital resources. See "Contractual Cash Obligations and Other Commitments" below for more information regarding off-balance sheet arrangements.

Contractual Cash Obligations and Other Commitments

In the course of ordinary business activities, QEP enters into a variety of contractual cash obligations and other commitments. The following table summarizes the significant contractual cash obligations as of December 31, 2014:

	Payments Due by Year [1]						
	Total	2015	2016	2017	2018	2019	After 2019
	(in millions)						
Long-term debt	$ 2,221.8	$ —	$ 176.8	$ —	$ 134.0	$ —	$ 1,911.0
Interest on fixed-rate, long-term debt [2]	852.8	133.0	129.5	122.3	115.5	113.2	239.3
Drilling contracts	29.5	21.6	7.9	—	—	—	—
Gathering, processing, firm transportation and storage [3]	978.3	109.1	112.7	120.0	117.1	112.0	407.4
Asset retirement obligations [4]	195.1	1.3	5.2	3.5	3.7	2.6	178.8
Operating leases	62.6	8.4	8.2	8.4	6.9	6.8	23.9
Total	$ 4,340.1	$ 273.4	$ 440.3	$ 254.2	$ 377.2	$ 234.6	$ 2,760.4

(1) This table excludes the Company's benefit plan liabilities as future payment dates are unknown. See Note 12 - Employee Benefits, in Item 8 of Part II of this Annual Report on Form 10-K for additional information.
(2) Excludes variable rate debt interest payments related to the Company's credit facility.
(3) Includes firm transportation rates that are subject to FERC approval and may change as a result of the outcome of pending approvals.
(4) These future obligations are discounted estimates of future expenditures based on expected settlement dates. See Note 5 - Asset Retirement Obligations, in Item 8 of Part II in this Annual Report on Form 10-K for additional information.

Impact of Inflation and Pricing

QEP's transactions are denominated in U.S. dollars. Inflation in the context of oil field services and goods has been significant in primary areas in which QEP operates. Typically, as prices for oil and gas increase, associated costs rise. Conversely, cost declines are likely to lag and may not adjust downward in proportion to declining prices. Changes in prices impact QEP's revenues, estimates of reserves, assessments of any impairment of oil and gas properties, as well as values of properties being acquired or sold. Price changes have the potential to affect QEP's ability to raise capital, borrow money, and retain personnel. While QEP does not presently expect business costs to materially rise from where they are today, higher prices for oil and gas could result in increases in the costs of materials, services and personnel.

Critical Accounting Policies, and Estimates

QEP's significant accounting policies are described in Note 1 - Summary of Significant Accounting Policies, in Item 8 of Part II of this Annual Report on Form 10-K. The Company's Consolidated Financial Statements are prepared in accordance with GAAP. The preparation of consolidated financial statements requires management to make assumptions and estimates that affect the reported results of operations and financial position. The following accounting policies may involve a higher degree of complexity and judgment on the part of management.

Oil and Gas Reserves

One of the most significant estimates the Company makes is the estimate of oil, gas and NGL reserves. Oil, gas and NGL reserve estimates require significant judgments in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may change substantially over time as a result of numerous factors including, but not limited to, additional development activity, production history, projected future production, economic assumptions relating to commodity prices, operating expenses, severance and other taxes, capital expenditures and remediation costs. The subjective judgments and variances in data for various fields make these estimates less precise than other estimates included in the financial statement disclosures.

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

QEP Energy engages independent reservoir engineering consultants to prepare estimates of the proved oil and gas reserves. Reserve estimates are based on a complex and highly interpretive process that is subject to continuous revision as additional production and development drilling information becomes available. See Note 16 - Supplemental Oil and Gas Information (Unaudited), in Item 8 of Part II of this Annual Report on Form 10-K.

Successful Efforts Accounting for Oil and Gas Operations
The Company follows the successful efforts method of accounting for oil and gas property acquisitions, exploration, development and production activities. Under this method, the acquisition costs of proved and unproved properties, successful exploratory wells and development wells are capitalized. Other exploration costs, including geological and geophysical costs, delay rentals and administrative costs associated with unproved property and unsuccessful exploratory well costs are expensed. Costs to operate and maintain wells and field equipment are expensed as incurred. Capitalized costs of unproved properties are reclassified as proved property when related proved reserves are determined or charged against the impairment allowance when abandoned.

Capitalized proved property acquisition costs are amortized by field using the unit-of-production method based on total proved reserves. Capitalized exploratory well and development costs are amortized similarly by field based on proved developed reserves. The calculation takes into consideration estimated future equipment dismantlement, surface restoration and property abandonment costs, net of estimated equipment salvage values. Other property and equipment are generally depreciated using the straight-line method over estimated useful lives. A gain or loss is generally recognized only when an entire field is sold or abandoned, or if the unit-of-production amortization rate would be significantly affected.

Impairment of Long-Lived Assets
Proved oil and gas properties are evaluated on a field-by-field basis for potential impairment. Other properties are evaluated on a specific-asset basis or in groups of similar assets, as applicable. Impairment is indicated when a triggering event occurs and/or the sum of the estimated undiscounted future net cash flows of an evaluated asset is less than the asset's carrying value. Triggering events could include, but are not limited to, an impairment of oil and gas reserves caused by mechanical problems, faster-than-expected decline of reserves, lease ownership issues and declines in oil, gas and NGL prices. If impairment is indicated, fair value is calculated using a discounted-cash flow approach. Cash flow estimates require forecasts and assumptions for many years into the future for a variety of factors, including commodity prices, operating costs and estimates of proved, probable and possible reserves. Cash flow estimates relating to future cash flows from probable and possible reserves are reduced by additional risk-weighting factors. During the years ended December 31, 2014, 2013 and 2012, QEP recorded impairment charges of $1,041.4 million, $1.2 million and $107.6 million, respectively, on some of its higher cost, proved properties in both of its Northern and Southern regions. The 2014 impairment charge related to the reduced value of these areas resulting from lower forward prices.

Unproved properties are evaluated on a specific-asset basis or in groups of similar assets, as applicable. The Company performs periodic assessments of unproved oil and gas properties for impairment and recognizes a loss at the time of impairment. In determining whether an unproved property is impaired, the Company considers numerous factors including, but not limited to, current development and exploration drilling plans, favorable or unfavorable exploration activity on adjacent leaseholds, in-house geologists' evaluation of the lease, future reserve cash flows and the remaining lease term. During the years ended December 31, 2014, 2013 and 2012, QEP recorded impairment charges of $101.8 million, $32.3 million and $25.4 million respectively, on its unproved properties.

Goodwill was evaluated on a reporting unit basis for potential impairment. Goodwill was tested for impairment under a two-step quantitative test on an annual basis or when a triggering event occurred. Under the first step, the estimated fair value of the reporting unit is compared with its carrying value (including goodwill). If the estimated fair value of the reporting unit was less than its carrying value, an indication of goodwill impairment existed for the reporting unit and the enterprise performed step two of the impairment test (measurement). Under step two, an impairment loss was recognized for any excess of the carrying amount of the reporting unit’s goodwill over the implied fair value of that goodwill. The implied fair value of goodwill was determined by allocating the fair value of the reporting unit in a manner similar to a purchase price allocation in acquisition accounting. During the year ended December 31, 2013, QEP recorded a $59.5 million impairment of goodwill related to assets in the Uinta Basin, reducing goodwill to zero as of December 31, 2013. During the year ended December 31, 2012, no goodwill impairment was recorded.

Asset Retirement Obligations
QEP is obligated to fund the costs of disposing of long-lived assets upon their abandonment. The majority of QEP's asset retirement obligations (ARO) relate to the plugging of wells and the related abandonment of oil and gas properties. QEP's ARO are recorded at estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at QEP's credit-adjusted risk-free interest rate. Revisions to estimated ARO can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment. QEP's ARO liability at December 31, 2014, 2013 and 2012, was $195.1 million, $165.1 million and $155.6 million, respectively.

Accounting for Derivative Contracts
The Company uses derivative contracts, typically fixed-price swaps and costless collars, to protect against a decline in the price it receives from its production. Accounting rules for derivatives require marking these instruments to fair value at the balance sheet reporting date. The change in fair value is reported in net income. See Note 7 - Derivative Contracts, in Item 8 of Part II of this Annual Report on Form 10-K for additional information.

Revenue Recognition
Revenues are recognized in the period that services are provided or products are delivered. QEP Energy uses the sales method of accounting whereby revenue is recognized as gas, oil and NGL is sold to purchasers. Revenues include estimates for the two most recent months using published commodity-price indexes and volumes supplied by field operators. An imbalance liability is recorded to the extent that QEP Energy has sold volumes in excess of its share of remaining reserves in an underlying property. QEP Marketing presents revenues on a gross basis. QEP uses derivatives to secure a known price for a specific volume over a specific time period. QEP Marketing does not engage in speculative hedging transactions, nor does it buy and sell energy contracts with the objective of generating profits on short-term differences in prices.

Litigation and Other Contingencies
In accordance with ASC 450, *Contingencies*, an accrual is recorded for a loss contingency when its occurrence is probable and damages can be reasonably estimable based on the anticipated most likely outcome or the minimum amount within a range of possible outcomes. Because legal proceedings are inherently unpredictable and unfavorable resolutions can occur, assessing contingencies is highly subjective and requires judgments about future events. When evaluating contingencies, QEP may be unable to provide a meaningful estimate due to a number of factors, including the procedural status of the matter in question, the presence of complex or novel legal theories, or the ongoing discovery and development of information important to the matter. QEP regularly reviews contingencies to determine the adequacy of its accruals and related disclosures. The amount of ultimate loss may differ from these estimates. See Note 10 - Commitments and Contingencies, in Item 8 of Part II of this Annual Report on Form 10-K for additional information regarding litigation and other contingencies.

Environmental Obligations
Management makes judgments and estimates in accordance with applicable accounting rules when it establishes reserves for environmental remediation, litigation and other contingent matters. Provisions for such matters are charged to expense when it is probable that a liability has been incurred and reasonable estimates of the liability can be made. Estimates of environmental liabilities are based on a variety of matters, including, but not limited to, the stage of investigation, the stage of the remedial design, evaluation of existing remediation technologies, and presently enacted laws and regulations. In future periods, a number of factors could significantly change QEP's estimate of environmental remediation costs, such as changes in laws and regulations, changes in the interpretation or administration of laws and regulations, revisions to the remedial design, unanticipated construction problems, identification of additional areas or volumes of contaminated soil and groundwater, and changes in costs of labor, equipment and technology. Consequently, it is not possible for management to reliably estimate the amount and timing of all future expenditures related to environmental matters and actual costs may vary significantly. See Note 10 - Commitments and Contingencies, in Item 8 of Part II of this Annual Report on Form 10-K for additional information regarding current environmental claims.

Benefit Plan Obligations
QEP maintains closed, non-contributory defined-benefit pension plans, including both a qualified and a supplemental plan. QEP also provides certain health care and life insurance benefits for certain retired employees. Determination of the benefit obligations for QEP's defined-benefit pension and postretirement plans impacts the recorded amounts for such obligations on the Consolidated Balance Sheets and the amount of benefit expense recorded to the Consolidated Income Statement.

Accounting for pension and other postretirement benefit obligations involves many assumptions, the most significant of which are the discount rate used to measure the present value of plan benefit obligations, the expected long-term rates of return on plan assets and the rate of future increases in compensation levels of participating employees. See Note 12 - Employee Benefits, in Item 8 of Part II of this Annual Report on Form 10-K for additional information.

Equity-Based Compensation
QEP issues stock options and restricted shares to certain officers, employees and non-employee directors under its Long-Term Stock Incentive Plan (LTSIP). QEP uses the Black-Scholes-Merton mathematical model to estimate the fair value of stock options for accounting purposes. The granting of restricted shares results in recognition of compensation cost measured at the grant-date market price. QEP uses an accelerated method in recognizing equity-based compensation costs with graded-vesting periods. Stock options held by employees generally vest in three equal, annual installments and primarily have a term of seven years. Restricted shares vest in equal installments over a specified number of years after the grant date with the majority vesting in three years. Non-vested restricted shares have voting and dividend rights; however, sale or transfer is restricted. The Company also awards performance share units under its Cash Incentive Plan (CIP) that are paid out in cash depending upon the Company's total shareholder return compared to a group of its peers over a three-year period. The performance share unit's compensation cost is equal to its fair value as of the period end and is classified as a liability. For a summary of LTSIP and CIP transactions see Note 11 - Equity-Based Compensation, in Item 8 of Part II of this Annual Report on Form 10-K for additional information.

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

Purchase Price Allocations
QEP periodically acquires assets and assumes liabilities in transactions accounted for as business combinations, such as the Permian Basin Acquisition and the Williston Basin Acquisition. In connection with a business combination, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Any excess or shortage of amounts assigned to assets and liabilities over or under the purchase price is recorded as a gain on bargain purchase or goodwill. The amount of goodwill or gain on bargain purchase recorded in any particular business combination can vary significantly depending upon the values attributed to assets acquired and liabilities assumed.

In estimating the fair values of assets acquired and liabilities assumed in a business combination, QEP makes various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved and unproved oil and gas properties. If sufficient market data is not available regarding the fair values of proved and unproved properties, QEP must prepare estimates. To estimate the fair values of these properties, QEP prepares estimates of gas, oil and NGL reserves. QEP estimates future prices to apply to the estimated reserves quantities acquired and estimates future operating and development costs to arrive at estimates of future net cash flows. For estimated proved reserves, the future net cash flows are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the acquisition. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved reserves, when a discounted cash flow model is used, the discounted future net cash flows of probable and possible reserves are reduced by additional risk factors. In some instances, market comparable information of recent transactions is used to estimate fair value of unproved acreage.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in higher DD&A expense, which results in lower net earnings. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses and development costs. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value, or if future operating expenses or development costs are higher than those originally used to determine fair value. Impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded. See Note 2 - Acquisitions and Divestitures, in Item 8 of Part II of this Annual Report on Form 10-K for additional information regarding purchase price allocations.

Recent Accounting Developments
See Recent Accounting Developments in Note 1 - Summary of Significant Accounting Policies, in Item 8 of Part II of this Annual Report on Form 10-K.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Price Risk Management

QEP uses commodity price derivative instruments in the normal course of business to reduce the risk of adverse commodity price movements. However, these same arrangements typically limit future gains from favorable price movements. The types of commodity derivative instruments currently utilized by the Company are generally fixed-price swaps or collars. The volume of commodity derivative instruments utilized by the Company may vary from year-to-year based on QEP's forecasted production. The derivative instruments currently utilized by the Company do not have margin requirements or collateral provisions that would require payments prior to the scheduled cash settlement dates. As of December 31, 2014, QEP held commodity price derivative contracts totaling 74.0 million MMBtu of gas and 9.1 million barrels of oil. At December 31, 2013, the QEP derivative contracts covered 93.4 million MMBtu of gas and 13.5 million barrels of oil.

The following table presents open 2015 derivative positions, which includes what was in effect as of December 31, 2014 (see Note 7 - Derivative Contracts, in Item 8 of Part II of this Annual Report on Form 10-K for table as of December 31, 2014) and what is known to be in effect as of February 20, 2015:

QEP Energy Commodity Derivative Positions

Year	Type of Contract	Index	Total Volumes	Swaps	
				Average price per unit	
			(in millions)		
Gas sales			**(MMBtu)**		
2015	Swap	NYMEX HH	58.1	$	3.48
2015	Swap	IFNPCR	39.8	$	3.55
2016	Swap	NYMEX HH	11.0	$	3.32
2016	Swap	IFNPCR	7.3	$	3.02
Oil sales			**(Bbls)**		
2015	Swap	NYMEX WTI	6.7	$	88.49
2015	Swap	ICE Brent	0.3	$	104.95
2016	Swap	NYMEX WTI	0.4	$	90.00

QEP Energy Crude Oil Sales Costless Collars

Year	Index	Total Volume Bbls	Average Price Floor		Average Price Ceiling	
		(in millions)				
2015	NYMEX WTI	0.4	$	50.00	$	63.83

QEP Energy Gas Sales Basis Swaps

Year	Index	Index Less Differential	Total Volumes MMBtu	Weighted Average Differential	
Gas basis swaps			(in millions)		
2015	NYMEX HH	IFNPCR	27.5	$	0.30

QEP Marketing Commodity Derivative Positions

Year	Type of Contract	Index	Total Volumes	Average Swap price per MMBtu	
			(in millions)		
Gas sales			**(MMBtu)**		
2015	Swap	IFNPCR	1.9	$	3.57
2016	Swap	IFNPCR	1.4	$	3.34
Gas purchases			**(MMBtu)**		
2015	Swap	IFNPCR	1.1	$	2.97

Changes in the fair value of derivative contracts from December 31, 2013 to December 31, 2014, are presented below:

		Commodity derivative contracts
		(in millions)
Net fair value of gas and oil derivative contracts outstanding at December 31, 2013	$	(23.5)
Contracts settled		3.5
Change in oil and gas prices on futures markets		47.3
Contracts added		321.6
Net fair value of gas and oil derivative contracts outstanding at December 31, 2014	**$**	**348.9**

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

		December 31, 2014
		(in millions)
Net fair value - asset (liability)	$	**348.9**
Fair value if market prices of gas, oil and NGL and basis differentials decline by 10%		**417.7**
Fair value if market prices of gas, oil and NGL and basis differentials increase by 10%		**279.8**

Utilizing the actual derivative contractual volumes, a 10% increase in underlying commodity prices would reduce the fair value of these instruments by $69.1 million, while a 10% decrease in underlying commodity prices would increase the fair value of these instruments by $68.8 million as of December 31, 2014. However, a gain or loss eventually would be substantially offset by the actual sales value of the physical production covered by the derivative instruments. For additional information regarding the Company's commodity derivative transactions, see Note 7 - Derivative Contracts, in Item 8 of Part II of this Annual Report on Form 10-K.

Interest-Rate Risk Management

The Company's ability to borrow and the rates offered by lenders can be adversely affected by illiquid credit markets as described in the Risk Factors, in Item 1A of Part I of this Annual Report on Form 10-K. The Company's credit facility has a floating interest rate which exposes QEP to interest rate risk. At December 31, 2014, the Company did not have any borrowings outstanding under its credit facility. If interest rates were to increase or decrease 10% during the year ended December 31, 2014, at our average level of borrowing for the year, the Company's interest expense would increase or decrease by $1.3 million for the year ended December 31, 2014, or approximately 1% of total interest expense.

The Company’s term loan, which was repaid and terminated in December 2014, had a floating interest rate which exposed QEP to interest rate risk. QEP entered into interest rate swap contracts to minimize the interest rate volatility risk associated with its term loan which were settled along with term loan extinguishment in December 2014.

The remaining $2,221.8 million of the Company's debt is fixed rate senior notes that are not subject to interest rate movements.
For additional information regarding the Company's debt instruments, see Note 9 - Debt, in Item 8 of Part II of this Annual Report on Form 10-K.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, comprehensive income, equity and cash flows present fairly, in all material respects, the financial position QEP Resources, Inc at December 31, 2014 and December 31, 2013 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule for each of the three years ended December 31, 2014 appearing under Item 15(c) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014 based on criteria established in *Internal Control - Integrated (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Assessment of Internal Control Over Financial Reporting under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

Houston, Texas

February 24, 2015

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2014	2013	2012
REVENUES	(in millions, except per share amounts)		
Gas sales	**$ 776.4**	$ 779.0	$ 667.4
Oil sales	**1,368.5**	916.6	532.6
NGL sales	**223.3**	192.2	184.2
Other revenues	**11.1**	22.4	27.5
Purchased gas, oil and NGL sales	**1,035.0**	774.9	660.0
Total Revenues	**3,414.3**	2,685.1	2,071.7
OPERATING EXPENSES			
Purchased gas, oil and NGL expense	**1,031.2**	783.5	670.7
Lease operating expense	**240.1**	181.3	175.8
Gas, oil and NGL transportation and other handling costs	**277.6**	222.0	198.1
Gathering and other expense	**6.7**	8.4	8.2
General and administrative	**204.4**	160.4	248.4
Production and property taxes	**205.2**	161.3	98.5
Depreciation, depletion and amortization	**994.7**	963.8	850.2
Exploration expenses	**9.9**	11.9	11.2
Impairment	**1,143.2**	93.0	133.0
Total Operating Expenses	**4,113.0**	2,585.6	2,394.1
Net gain (loss) from asset sales	**(148.6)**	103.5	1.2
OPERATING INCOME (LOSS)	**(847.3)**	203.0	(321.2)
Realized and unrealized gains (losses) on derivative contracts (Note 7)	**363.3**	58.9	433.5
Interest and other income	**12.8**	15.2	15.0
Income from unconsolidated affiliates	**0.3**	0.2	0.1
Loss from early extinguishment of debt	**(2.0)**	—	(0.6)
Interest expense	**(169.1)**	(165.1)	(126.3)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	**(642.0)**	112.2	0.5
Income tax (provision) benefit	**232.5**	(60.1)	1.9
NET INCOME (LOSS) FROM CONTINUING OPERATIONS	**(409.5)**	52.1	2.4
Net income from discontinued operations, net of income tax	**1,193.9**	107.3	125.9
NET INCOME ATTRIBUTABLE TO QEP	**$ 784.4**	$ 159.4	$ 128.3
Earnings (Loss) Per Common Share Attributable to QEP			
Basic from continuing operations	**$ (2.28)**	$ 0.29	$ 0.01
Basic from discontinued operations	**6.64**	0.60	0.71
Basic total	**$ 4.36**	$ 0.89	$ 0.72
Diluted from continuing operations	**$ (2.28)**	$ 0.29	$ 0.01
Diluted from discontinued operations	**6.64**	0.60	0.71
Diluted total	**$ 4.36**	$ 0.89	$ 0.72
Weighted-average common shares outstanding			
Used in basic calculation	**179.8**	179.2	177.8
Used in diluted calculation	**179.8**	179.5	178.7
Dividends per common share	**$ 0.08**	$ 0.08	$ 0.08

See Notes accompanying the Consolidated Financial Statements.

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

	Year Ended December 31,		
	2014	2013	2012
	(in millions)		
Net income attributable to QEP	**$ 784.4**	$ 159.4	$ 128.3
Other comprehensive income (loss), net of tax:			
Reclassification of previously deferred derivative losses [1]	**—**	(77.6)	(171.1)
Pension and other postretirement plans adjustments:			
Current year net actuarial gain (loss) [2]	**(13.6)**	13.5	(10.0)
Amortization of net actuarial loss [3]	**0.5**	1.5	1.1
Amortization of net prior service cost [4]	**9.7**	3.3	3.5
Net curtailment and settlements cost incurred [5]	**5.6**	—	1.4
Total pension and other postretirement plan adjustments	**2.2**	18.3	(4.0)
Other comprehensive income (loss)	**2.2**	(59.3)	(175.1)
Comprehensive income (loss) attributable to QEP	**$ 786.6**	$ 100.1	$ (46.8)

(1) Presented net of income tax benefit of $45.9 million and $101.3 million during the years ended December 31, 2013 and 2012, respectively.
(2) Presented net of income tax benefit of $8.5 million for the year ended December 31, 2014, net of income tax expense of $8.3 million during the year ended December 31, 2013 and net of income tax benefit of $6.3 million during the year ended December 31, 2012.
(3) Presented net of income tax expense of $0.3 million, $0.9 million and $0.9 million during the years ended December 31, 2014, 2013, and 2012, respectively.
(4) Presented net of income tax expense of $6.0 million, $2.1 million and $2.2 million during the years ended December 31, 2014, 2013 and 2012, respectively.
(5) Presented net of income tax expense of $3.5 million for the year ended December 31, 2014 and $0.8 million during the year ended December 31, 2012.

See Notes accompanying the Consolidated Financial Statements.

QEP RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS

	December 31, 2014	December 31, 2013
ASSETS	(in millions)	
Current Assets		
Cash and cash equivalents	**$ 1,160.1**	$ 11.9
Accounts receivable, net	**441.9**	330.3
Fair value of derivative contracts	**339.0**	0.2
Gas, oil and NGL inventories, at lower of average cost or market	**13.7**	13.4
Deferred income taxes - current	**—**	27.9
Prepaid expenses and other	**46.8**	45.4
Current assets of discontinued operations	**—**	122.0
Total Current Assets	**2,001.5**	551.1
Property, Plant and Equipment (successful efforts method for oil and gas properties)		
Proved properties	**12,278.7**	11,571.4
Unproved properties	**825.2**	665.1
Marketing and other	**293.8**	282.8
Materials and supplies	**54.3**	54.3
Total Property, Plant and Equipment	**13,452.0**	12,573.6
Less Accumulated Depreciation, Depletion and Amortization		
Exploration and production	**6,153.0**	4,930.9
Marketing and other	**67.8**	50.2
Total Accumulated Depreciation, Depletion and Amortization	**6,220.8**	4,981.1
Net Property, Plant and Equipment	**7,231.2**	7,592.5
Fair value of derivative contracts	**9.9**	1.0
Restricted cash	**—**	50.0
Other noncurrent assets	**44.2**	46.6
Noncurrent assets of discontinued operations	**—**	1,167.7
TOTAL ASSETS	**$ 9,286.8**	$ 9,408.9
LIABILITIES AND EQUITY		
Current Liabilities		
Checks outstanding in excess of cash balances	**$ 54.7**	$ 109.1
Accounts payable and accrued expenses	**575.4**	361.9
Income taxes payable	**532.1**	8.7
Production and property taxes	**61.7**	54.7
Interest payable	**36.4**	37.2
Fair value of derivative contracts	**—**	26.7
Deferred income taxes	**84.5**	—
Current liabilities of discontinued operations	**—**	75.3
Total Current Liabilities	**1,344.8**	673.6
Long-term debt	**2,218.1**	2,997.5
Deferred income taxes	**1,362.7**	1,364.9
Asset retirement obligations	**193.8**	163.3
Other long-term liabilities	**92.1**	94.5
Noncurrent liabilities of discontinued operations	**—**	238.3
Commitments and contingencies (Note 10)		
EQUITY		
Common stock - par value $0.01 per share; 500.0 million shares authorized; 176.2 million and 179.7 million shares issued, respectively	**1.8**	1.8
Treasury stock - 0.8 million and 0.4 million shares, respectively	**(25.4)**	(14.9)
Additional paid-in capital	**535.3**	498.4
Retained earnings	**3,587.9**	2,917.8
Accumulated other comprehensive income (loss)	**(24.3)**	(26.5)
Total Common Shareholders' Equity	**4,075.3**	3,376.6
Noncontrolling interest	**—**	500.2
Total Equity	**4,075.3**	3,876.8
TOTAL LIABILITIES AND EQUITY	**$ 9,286.8**	$ 9,408.9

See Notes accompanying the Consolidated Financial Statements.

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF EQUITY

	Common Stock		Treasury Stock		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income(Loss)	Non-controlling Interest	Total
	Shares	Amount	Shares	Amount					
	(in millions)								
Balance at December 31, 2011	177.2	$ 1.8	(0.4)	$ (13.1)	$ 431.4	$ 2,673.5	$ 207.9	$ 50.6	$ 3,352.1
Net income attributable to QEP	—	—	—	—	—	128.3	—	3.7	132.0
Dividends paid	—	—	—	—	—	(14.2)	—	—	(14.2)
Equity-based compensation	1.3	—	0.2	7.1	30.7	(14.6)	—	—	23.2
Distribution to QEP Education Foundation	—	—	0.1	2.3	—	—	—	—	2.3
Distribution of noncontrolling interest	—	—	—	—	—	—	—	(6.6)	(6.6)
Reclassification of previously deferred derivative gains in OCI, net of tax	—	—	—	—	—	—	(171.1)	—	(171.1)
Change in pension and postretirement liability, net of tax	—	—	—	—	—	—	(4.0)	—	(4.0)
Balance at December 31, 2012	178.5	1.8	(0.1)	(3.7)	462.1	2,773.0	32.8	47.7	3,313.7
Net income attributable to QEP	—	—	—	—	—	159.4	—	12.0	171.4
Dividends paid	—	—	—	—	—	(14.3)	—	—	(14.3)
Equity-based compensation	1.2	—	(0.3)	(11.2)	36.3	(0.3)	—	0.2	25.0
Distribution of noncontrolling interest	—	—	—	—	—	—	—	(9.3)	(9.3)
Net proceeds from QEP Midstream initial public offering	—	—	—	—	—	—	—	449.6	449.6
Reclassification of previously deferred derivative gains in OCI, net of tax	—	—	—	—	—	—	(77.6)	—	(77.6)
Change in pension and postretirement liability, net of tax	—	—	—	—	—	—	18.3	—	18.3
Balance at December 31, 2013	179.7	1.8	(0.4)	(14.9)	498.4	2,917.8	(26.5)	500.2	3,876.8
Net income attributable to QEP	**—**	**—**	**—**	**—**	**—**	**784.4**	**—**	**—**	**784.4**
Dividends paid	**—**	**—**	**—**	**—**	**—**	**(14.6)**	**—**	**—**	**(14.6)**
Equity-based compensation	**1.2**	**—**	**(0.4)**	**(10.5)**	**36.9**	**—**	**—**	**0.2**	**26.6**
Distribution of noncontrolling interest	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**(31.9)**	**(31.9)**
Common stock repurchased and retired	**(4.7)**	**—**	**—**	**—**	**—**	**(99.7)**	**—**	**—**	**(99.7)**
Noncontrolling interest decrease from Midstream Sale	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**(468.5)**	**(468.5)**
Change in pension and postretirement liability, net of tax	**—**	**—**	**—**	**—**	**—**	**—**	**2.2**	**—**	**2.2**
Balance at December 31, 2014	**176.2**	**$ 1.8**	**(0.8)**	**$ (25.4)**	**$ 535.3**	**$ 3,587.9**	**$ (24.3)**	**$ —**	**$ 4,075.3**

See Notes accompanying the Consolidated Financial Statements.

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2014	2013	2012
OPERATING ACTIVITIES	(in millions)		
Net income attributable to QEP	**$ 784.4**	$ 159.4	$ 128.3
Net income attributable to noncontrolling interest	**21.6**	12.0	3.7
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**1,040.6**	1,016.0	905.3
Deferred income taxes	**(84.1)**	66.1	32.1
Impairment	**1,143.2**	93.0	133.0
Equity-based compensation	**27.2**	27.1	25.6
Amortization of debt issuance costs and discounts	**6.7**	6.4	5.3
Net gain from asset sales	**(1,644.8)**	(103.0)	(1.2)
Income from unconsolidated affiliates	**(5.2)**	(5.8)	(6.8)
Distributions from unconsolidated affiliates and other	**9.4**	7.9	7.9
Non-cash loss on early extinguishment of debt	**4.4**	—	—
Unrealized (gains) losses on derivative contracts	**(374.4)**	88.7	(63.2)
Changes in operating assets and liabilities			
Accounts receivable	**(160.5)**	3.2	9.6
Inventories	**(20.2)**	2.6	28.7
Prepaid expenses	**(7.3)**	14.0	(16.8)
Accounts payable and accrued expenses	**320.1**	(179.7)	101.3
Federal income taxes	**494.1**	(27.4)	3.5
Other	**(12.7)**	11.2	(0.3)
Net Cash Provided by Operating Activities	**1,542.5**	1,191.7	1,296.0
INVESTING ACTIVITIES			
Property acquisitions	**(960.5)**	(40.9)	(1,406.1)
Property, plant and equipment, including dry hole exploratory well expense	**(1,765.9)**	(1,561.7)	(1,393.6)
Proceeds from disposition of assets	**3,296.6**	211.1	5.2
Acquisition deposit held in escrow	**50.0**	(50.0)	—
Other investments	**(42.0)**	—	—
Net Cash Provided by (Used in) Investing Activities	**578.2**	(1,441.5)	(2,794.5)
FINANCING ACTIVITIES			
Checks outstanding in excess of cash balances	**(54.4)**	69.3	10.3
Long-term debt issued	**300.0**	—	1,450.0
Long-term debt issuance costs paid	**(9.3)**	(3.2)	(17.8)
Long-term debt repaid	**(600.0)**	—	(6.7)
Proceeds from credit facility	**5,455.0**	3,085.0	2,739.0
Repayments of credit facility	**(5,935.0)**	(3,295.0)	(2,655.5)
Common stock repurchased and retired	**(99.7)**	—	—
Treasury stock repurchased	**(6.2)**	(9.3)	—
Other capital contributions	**6.0**	7.0	(2.2)
Dividends paid	**(14.6)**	(14.3)	(14.2)
Excess tax benefit on equity-based compensation	**(0.5)**	—	2.2
Net proceeds from the issuance of common units	**—**	449.6	—
Distribution to noncontrolling interest	**(31.9)**	(9.3)	(6.6)
Net Cash (Used in) Provided by Financing Activities	**(990.6)**	279.8	1,498.5
Change in cash and cash equivalents	**1,130.1**	30.0	—
Beginning cash and cash equivalents	**30.0**	—	—
Ending cash and cash equivalents	**$ 1,160.1**	$ 30.0	$ —

See Notes accompanying the Consolidated Financial Statements.

Note 1 - Summary of Significant Accounting Policies

Nature of Business

QEP Resources, Inc. (QEP or the Company) is a holding company with two 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 the Haynesville Gathering System and an underground gas storage reservoir (QEP Marketing and Other).

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.

In October 2014, the Company announced that its wholly owned subsidiary, QEP Field Services Company (QEP Field Services), had entered into a definitive agreement to sell substantially all of its midstream business, including the Company's ownership interest in QEP Midstream Partners, LP (QEP Midstream), to Tesoro Logistics LP (Tesoro). On December 2, 2014, QEP closed the sale of its midstream business to Tesoro (Midstream Sale) for total cash proceeds of $2.5 billion, including $230.0 million to refinance debt at QEP Midstream, subject to post-closing adjustments, and QEP recorded a pre-tax gain of $1.8 billion on its Consolidated Statements of Operations in "Net income from discontinued operations, net of income tax" for the year ended December 31, 2014. The decision to sell the midstream business was the result of the Company’s ongoing review of strategic alternatives to maximize shareholder value. QEP Marketing retained ownership of the Haynesville Gathering System. As a result of the Midstream Sale, the QEP Field Services reporting segment, excluding the retained ownership of the Haynesville Gathering System, has been classified as a discontinued operation on the Consolidated Statement of Operations and the Notes accompanying the Consolidated Financial Statements. For reporting purposes, the Haynesville Gathering System, which was retained by QEP Marketing, has been combined with QEP Marketing and Other.

Shares of QEP’s common stock trade on the New York Stock Exchange under the ticker symbol “QEP”.

Principles of Consolidation

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

All dollar and share amounts in this Annual Report on Form 10-K are in millions, except per-share information and where otherwise noted.

Reclassifications

The 2013 and 2012 financial information has been recast so that the basis of presentation is consistent with that of the 2014 financial information. This recast reflects the financial condition and results of operations of QEP Field Services, excluding the Haynesville Gathering System, as discontinued operations for all periods presented. For reporting purposes, the retained Haynesville Gathering System has been combined with QEP Marketing and Other. For a summary of discontinued operations see Note 3 - Discontinued Operations.

Use of Estimates

The preparation of the Consolidated Financial Statements and Notes in conformity with GAAP requires that management formulate estimates and assumptions that affect revenues, expenses, assets, liabilities and the disclosure of contingent assets and liabilities. A significant item that requires management's estimates and assumptions is the estimate of proved gas, oil and NGL reserves which are used in the calculation of depreciation, depletion and amortization rates of its oil and gas properties, impairment of proved properties and asset retirement obligations. Changes in estimated quantities of its reserves could impact the Company's reported financial results as well as disclosures regarding the quantities and value of proved oil and gas reserves. Other items subject to estimates and assumptions include the carrying amount of property, plant and equipment, assigning fair value and allocating purchase price in connection with business combinations, valuation allowances for receivables, income taxes, valuation of derivatives instruments, accrued liabilities, accrued revenue and related receivables and obligations related to employee benefits, among others. Although management believes these estimates are reasonable, actual results could differ from these estimates.

Risks and Uncertainties

The Company’s revenue, profitability and future growth are substantially dependent upon the prevailing and future prices for gas, oil and NGL, each of which depend on numerous factors beyond the Company’s control such as economic conditions, regulatory developments, global supply and demand and competition from other energy sources. The energy markets historically have been volatile and oil and gas prices at the end of 2014 and during the first part of 2015 have been substantially lower than recent historical averages, and may be subject to significant fluctuations in the future. The Company’s derivative contracts serve to mitigate a portion of the effect of this price volatility on the Company’s cash flows, and the Company has derivative contracts in place for a portion of its expected 2015 and 2016 oil and gas production. See Note 7 - Derivative Contracts for the Company’s open oil and gas commodity derivative contracts. The Company is dependent on cash on hand, availability under its credit facility, along with cash flows from operating activities, to fund its capital expenditures. Based on its current cash on hand, anticipated oil and gas prices and availability under its credit facility, the Company expects to be able to fund its planned capital expenditures and operating expenses for 2015. However, a substantial or extended decline in oil and gas prices could have an adverse effect on the Company’s financial position, results of operations, cash flows and quantities of oil and gas reserves that may be economically produced, and could impact the Company’s ability to comply with the financial covenants under the credit facility and could limit further borrowings to fund capital expenditures. Additionally, as forward prices have continued to decline during 2015, there could be additional impairment charges to our oil and gas assets or other investments.

Revenue Recognition

QEP subsidiaries recognize revenues in the period that services are provided or products are delivered. Revenues associated with the sale of oil, gas and NGL are accounted for using the sales method, whereby revenue is recognized as oil, gas and NGL is sold to purchasers. A liability is recorded in the event that the Company has sold volumes in excess of its share of remaining oil and gas reserves in an underlying property. QEP's imbalance obligations at December 31, 2014 and 2013, were $7.9 million and $10.7 million, respectively.

QEP Marketing reports revenues on a gross basis because, in the judgment of management, the nature and circumstances of its marketing transactions are consistent with guidance for gross revenue reporting. QEP Marketing markets affiliate and third-party gas, oil and NGL volumes. QEP Marketing uses derivatives to secure a known price for a specific volume over a specific time period. QEP Marketing does not engage in speculative hedging transactions, nor does it buy and sell energy contracts with the objective of generating profits on short-term differences in price. QEP Marketing has not engaged in buy/sell arrangements, as described in ASC 845-10-25-4, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*.

In most states in which QEP Energy operates, QEP pays production taxes based on a percentage of field-level revenue, except in Louisiana, where severance taxes are volume based.

Cash and Cash Equivalents and Restricted Cash

Cash equivalents consist principally of highly liquid investments in securities with maturities of three months or less made through commercial-bank accounts that result in available funds the next business day.

As of December 31, 2014, none of QEP's cash and cash equivalents were restricted. As of December 31, 2013, QEP's restricted cash balance was $50.0 million, which consisted of a deposit paid by QEP that was held in escrow for an acquisition (see Note

2 - Acquisitions and Divestitures for further discussion on the acquisition). The cash payment is shown in investing activities on the Consolidated Statements of Cash Flows.

Supplemental cash flow information is shown in the below table:

	Year Ended December 31,		
	2014	2013	2012
Supplemental Disclosures:	(in millions)		
Cash paid for interest, net of capitalized interest	**$ 163.2**	$ 156.7	$ 105.1
Cash paid for income taxes	**0.3**	77.9	30.0
Non-cash investing activities			
Change in capital expenditure accrual balance	**$ 8.4**	$ (25.2)	$ 88.5

Accounts Receivable Trade

Accounts receivable trade consists mainly of receivables from oil and gas purchasers and joint interest owners on properties the Company operates. For receivables from joint interest owners, the Company has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Generally, the Company's oil and gas receivables are collected and bad debts are minimal. Bad debt expense associated with accounts receivable for the years ended December 31, 2014, 2013 and 2012, was $2.1 million, $0.1 million, and $1.3 million, respectively. The Company routinely assesses the recoverability of all material trade and other receivables to determine their collectability. The allowance for bad debt expenses was $4.6 million at December 31, 2014 and $2.2 million at December 31, 2013.

Property, Plant and Equipment

Property, plant and equipment balances are stated at historical cost. Material and supplies inventories are valued at the lower of cost or market. Maintenance and repair costs are expensed as incurred. Significant accounting policies for our property, plant and equipment are as follows:

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

Capitalized costs of unproved properties are reclassified to proved property when related proved reserves are determined or charged against the impairment allowance when abandoned.

Capitalized exploratory well costs
The Company capitalizes exploratory well costs until it determines whether an exploratory well is commercial or noncommercial. If the Company deems the well commercial, capitalized costs are depreciated on a field basis using the unit-of-production method and the estimated proved developed oil and gas reserves. If the Company concludes that the well is noncommercial, well costs are immediately charged to exploration expense. Exploratory well costs that have been capitalized for a period greater than one year since the completion of drilling are expensed unless the Company remains engaged in substantial activities to assess whether the well is commercial.

Depreciation, depletion and amortization
Capitalized proved leasehold costs are depleted on a field-by-field basis using the unit-of-production method and the estimated proved oil and gas reserves. Capitalized costs of exploratory wells that have found proved oil and gas reserves and capitalized development costs are depreciated using the unit-of-production method based on estimated proved developed reserves for a successful effort field. The Company capitalizes an estimate of the fair value of future abandonment costs.

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

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

Impairment of Long-Lived Assets

Proved oil and gas properties are evaluated on a field-by-field basis for potential impairment. Impairment is indicated when a triggering event occurs and/or the sum of the estimated undiscounted future net cash flows of an evaluated asset is less than the asset's carrying value. Triggering events could include, but are not limited to, an impairment of oil and gas reserves caused by mechanical problems, faster-than-expected decline of reserves, lease ownership issues, and other than temporary declines in gas, oil and NGL prices. If impairment is indicated, fair value is calculated using a discounted-cash flow approach. Cash flow estimates require forecasts and assumptions for many years into the future for a variety of factors, including commodity prices, operating costs, and estimates of proved, probable and possible reserves. Cash flow estimates relating to future cash flows from probable and possible reserves are reduced by additional risk-weighting factors.

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

During the year ended December 31, 2014, QEP recorded impairment charges of $1,143.2 million, of which $1,041.4 million related to price-related impairment charges on proved properties and $101.8 million related to impairment on unproved properties due to lower future prices, lease expirations and changes in drilling plans. Of the $1,143.2 million property impairment charges incurred during the year ended December 31, 2014, $1,116.8 million related to oil and gas properties in the Southern Region and $26.4 million related to oil and gas properties in the Northern Region.

During the year ended December 31, 2013, QEP recorded impairment charges of $93.0 million, of which $1.2 million was related to price-related impairment charges on proved properties and $32.3 million was related to impairment on unproved properties due to lease expirations and changes in drilling plans. An additional $59.5 million of impairment was recorded due to the write-off of goodwill (see Goodwill section within this note for additional information). Of the $33.5 million of property impairment charges incurred during the year ended December 31, 2013, $17.5 million related to oil and gas properties in the Southern Region and $16.0 million related to oil and gas properties in the Northern Region.

During the year ended December 31, 2012, QEP recorded impairment charges of $133.0 million on its oil and gas properties. Of the $133.0 million charges during the year ended December 31, 2012, $107.6 million related to price-related impairment charges on proved properties and $25.4 million related to impairment on unproved properties. The impairment charges reflect the reduced value of certain fields resulting from lower gas, oil and NGL prices and impairments of unproven leasehold acquisition costs. Of the $133.0 million impairment charges during the year ended December 31, 2012, $104.7 million related to oil and gas properties in the Southern Region and $28.3 million related to oil and gas properties in the Northern Region.

Asset Retirement Obligations

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

Litigation and Other Contingencies

In accordance with ASC 450, *Contingencies*, an accrual is recorded for a loss contingency when its occurrence is probable and damages can be reasonably estimated based on the anticipated most likely outcome or the minimum amount within a range of possible outcomes. QEP regularly reviews contingencies to determine the adequacy of its accruals and related disclosures. The amount of ultimate loss may differ from these estimates. See Note 10 - Commitments and Contingencies, for additional information.

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

Goodwill

Goodwill represents the excess of the amount paid over the fair value of net assets acquired in a business combination and is not subject to amortization. As of December 31, 2013, goodwill related to the Company's Uinta Basin reporting unit within QEP Energy was reduced to zero from $59.5 million in 2012 due to the recognition of impairment during 2013. Goodwill was tested for impairment under a two-step quantitative test on an annual basis or when a triggering event occurred. Under the first step, the estimated fair value of the reporting unit was compared with its carrying value (including goodwill). QEP determined fair value of its reporting units in which goodwill was allocated using the income approach in which the fair value was estimated based on the value of expected future cash flows. Key assumptions used in the cash flow model considered estimated quantities of oil, NGL and gas reserves, including both proved reserves and risk-adjusted unproved reserves, including probable and possible reserves; estimates of market prices considering forward commodity price curves as of the measurement date; and estimates of capital costs. If the fair value of the reporting unit exceeded its carrying value, step two did not need to be performed. If the estimated fair value of the reporting unit was less than its carrying value, an indication of goodwill impairment existed for the reporting unit and the enterprise performed step two of the impairment test (measurement). Under step two, an impairment loss was recognized for any excess of the carrying amount of the reporting unit's goodwill over the implied fair value of that goodwill. The implied fair value of goodwill was determined by allocating the fair value of the reporting unit in a manner similar to a purchase price allocation in acquisition accounting. The residual fair value after this allocation was the implied fair value of the reporting unit goodwill. Fair value of the reporting unit under the two-step assessment was determined using a discounted cash flow analysis.

During the performance of QEP's annual goodwill impairment test at December 31, 2013, QEP failed the first step of the goodwill impairment test as described above. This was due primarily to lower forecasted oil and NGL prices. QEP performed the second step test described above resulting in a full write down of the Uinta reporting unit's goodwill of $59.5 million as of December 31, 2013.

Derivative Instruments

Effective January 1, 2012, the Company elected to de-designate all of its gas, oil and NGL derivative contracts that were previously designated as cash flow hedges and the Company elected to discontinue hedge accounting prospectively. Accordingly, all realized and unrealized gains and losses are recognized in earnings immediately as derivative contracts are settled and marked-to-market. For the years ended December 31, 2014, 2013 and 2012, an unrealized gain of $374.4 million, an unrealized loss of $88.7 million and an unrealized gain of $63.2 million, respectively, were included in income that, prior to January 1, 2012, would have been deferred in Accumulated Other Comprehensive Income (AOCI) under hedge accounting (Refer to Note 7 - Derivative Contracts, for additional information). At December 31, 2011, AOCI consisted of $395.9 million ($248.6 million after tax) of unrealized gains, representing the mark-to-market value of the Company's cash flow hedges as of the balance sheet date, less any ineffectiveness recognized. QEP fully reclassified all unrealized gains in AOCI into earnings during 2012 and 2013.

All of QEP's derivative contracts are net settled in cash without delivery of product. These contracts also have a nominal quantity, exchange an index price for a fixed price, and are net settled with the brokers as the price bulletins become available. These derivative contracts are recorded in revenues or cost of sales in the month of settlement. Basis-only swaps are used to manage the risk of widening basis differentials. These contracts are marked-to-market monthly with any change in the valuation recognized in the determination of income.

Credit Risk

Exposure to credit risk may be affected by the concentration of customers in these regions due to changes in economic or other conditions. Customers include individuals and numerous commercial and industrial enterprises that may react differently to changing conditions. Management believes that its credit review procedures, loss reserves, customer deposits and collection procedures have adequately provided for usual and customary credit-related losses. Commodity-based hedging arrangements also expose the Company to credit risk. The Company monitors the creditworthiness of its counterparties, which generally are major financial institutions and energy companies. Loss reserves are periodically reviewed for adequacy and may be established on a specific case basis. QEP requests credit support and, in some cases, fungible collateral, financial guarantees, letters of credit or prepayment from companies with unacceptable credit risks. The Company has master-netting agreements with some counterparties that allow the offsetting of receivables and payables in a default situation.

The Company's five largest customers accounted for 33%, 38%, and 27% of QEP's revenues for the years ended December 31, 2014, 2013 and 2012, respectively. During the year ended December 31, 2014, Valero Marketing and Supply Company made up 10% of the Company's total revenues. During the year ended December 31, 2013, Freepoint Commodities, LLC and Arrow Midstream Holdings, LLC accounted for 13% and 11%, respectively, of the Company's total revenues. During the year ended December 31, 2012, no customer accounted for 10% or more of QEP's total revenues. All of the these customers represent QEP Energy's customers and 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.

Income Taxes

Deferred income taxes are provided for the temporary differences arising between the book and tax carrying amounts of assets and liabilities. These differences create taxable or tax-deductible amounts for future periods. The Company records interest earned on income tax refunds in interest and other income and records penalties and interest charged on tax deficiencies in interest expense.

ASC 740, *Income Taxes*, specifies the accounting for uncertainty in income taxes by prescribing a minimum recognition threshold for a tax position to be reflected in the financial statements. If recognized, the tax benefit is measured as the largest amount of tax benefit that is more-likely-than-not to be realized upon ultimate settlement. Management has considered the amounts and the probabilities of the outcomes that could be realized upon ultimate settlement and believes that it is more-likely-than-not that the Company's recorded income tax benefits will be fully realized. During the year ended December 31, 2014, the Company recorded a valuation allowance of $18.4 million against the state net operation loss deferred tax asset, because the sale of properties in Oklahoma in 2014 will preclude its utilization in the future. There were no unrecognized tax benefits at the beginning or end of the twelve-month periods ended December 31, 2013 and 2012. All federal income tax returns prior to 2014 have been examined by the Internal Revenue Service and are closed. Income tax returns for 2014 have not yet been filed. Most state tax returns for 2011 and subsequent years remain subject to examination.

Treasury Stock

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

Share Repurchases and Retirements

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 was extended through December 2015. The timing and amount of any QEP share repurchases will depend upon a number of factors, including general market conditions, the Company’s financial position and the estimated intrinsic value of the Company’s shares. The repurchase plan does not obligate QEP to acquire any specific number of shares and may be discontinued at any time. Shares repurchased under the plan represent common stock and are retired after repurchase. During December 2014, QEP repurchased 4,731,438 shares at a weighted average price of $21.08 per share, including commission of $0.02 per share, for $99.7 million under this program.

Earnings Per Share

Basic earnings per share (EPS) are computed by dividing net income attributable to QEP by the weighted-average number of common shares outstanding during the reporting period. Diluted EPS includes the potential increase in the number of outstanding shares that could result from the exercise of in-the-money stock options. QEP's unvested restricted shares are considered issued and outstanding, have a minimal historical forfeiture rate and receive dividends.

Unvested equity-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents are considered participating securities and are included in the computation of earnings per share pursuant to the two-class method. The Company's unvested restricted stock awards contain non-forfeitable dividend rights and participate equally with common stock with respect to dividends issued or declared. However, the Company's unvested restricted stock does not have a contractual obligation to share in losses of the Company. The Company's unexercised stock options do not contain rights to dividends. Under the two-class method, the earnings used to determine basic earnings per common share are reduced by an amount allocated to participating securities. When the Company records a net loss, none of the loss is allocated to the participating securities since the securities are not obligated to share in Company losses. Use of the two-class method has an insignificant impact on the calculation of basic and diluted earnings per common share. For the twelve months ended December 31, 2014, 0.3 million shares were not included in diluted common shares outstanding as they were anti-dilutive due to QEP's net loss from continuing operations. A reconciliation of the components of basic and diluted shares used in the EPS calculation follows:

	December 31,		
	2014	2013	2012
	(in millions)		
Weighted-average basic common shares outstanding	**179.8**	179.2	177.8
Potential number of shares issuable under the Long-Term Stock Incentive Plan	—	0.3	0.9
Average diluted common shares outstanding	**179.8**	179.5	178.7

Equity-Based Compensation

QEP issues stock options and restricted shares to certain officers, employees and non-employee directors under its Long-Term Stock Incentive Plan (LTSIP). QEP uses the Black-Scholes-Merton mathematical model to estimate the fair value of stock options for accounting purposes. The granting of restricted shares results in recognition of compensation cost measured at the grant-date market price. QEP uses an accelerated method in recognizing equity-based compensation costs with graded-vesting periods. Stock options held by employees generally vest in three equal, annual installments and primarily have a term of seven years. Restricted shares vest in equal installments over a specified number of years after the grant date with the majority vesting in three years. Non-vested restricted shares have voting and dividend rights; however, sale or transfer is restricted. The Company also awards performance share units under its Cash Incentive Plan (CIP), which are paid out in cash depending upon the Company's total shareholder return compared to a group of its peers over a three-year period. The performance share unit's compensation cost is equal to its fair value as of the period end and is classified as a liability. For a summary of LTSIP and CIP transactions see Note 11 - Equity-Based Compensation.

Pension Plans, Other Postretirement Benefits and Defined-Contribution Plans

QEP measures pension plan assets at fair value. Defined-benefit plan obligations and costs are actuarially determined, incorporating the use of various assumptions. Critical assumptions for pension and other postretirement plans include the discount rate, the expected rate of return on plan assets (for funded pension plans) and the rate of future compensation increases. Other assumptions involve demographic factors such as retirement, mortality and turnover. QEP evaluates and updates its actuarial assumptions at least annually.

Comprehensive Income

Comprehensive income is the sum of net income as reported in the Consolidated Statements of Operations and changes in the components of other comprehensive income. Other comprehensive income includes certain items that are recorded directly to equity and classified as AOCI. One component of other comprehensive income is changes in the market value of commodity-based derivative instruments for which the Company previously applied hedge accounting. Income or loss associated with such commodity-based derivative instruments was realized when the gas, oil or NGL underlying the derivative instrument was sold. Comprehensive income includes changes in the under-funded portion of the Company's defined benefit pension plans and other postretirement benefits plans and changes in deferred income taxes on such amounts. These transactions do not represent the culmination of the earnings process but result from periodically adjusting historical balances to fair value.

Business Segments

Line of business information is presented according to senior management's basis for evaluating performance considering differences in the nature of products, services and regulation. QEP's lines of business are QEP Energy and QEP Marketing and Other. QEP's former reporting segment, QEP Field Services, excluding the retained ownership of the Haynesville Gathering System, was sold in 2014 and has been classified as a discontinued operation on the Consolidated Statement of Operations and the Notes accompanying the Consolidated Financial Statements. The Haynesville Gathering System, which was retained by QEP Marketing, is included the reporting segment QEP Marketing and Other.

Recent Accounting Developments

In August 2014, the Financial Accounting Standards Board (FASB) issued ASU No. 2014-15, *Presentation of Financial Statements-Going Concern (Topic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern*. This guidance provides additional information to guide management's evaluation of whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date that the financial statements are issued. The update is effective for annual periods beginning on or after December 15, 2016. The Company is currently evaluating the impact of this standard on the Company's Consolidated Financial Statements.

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*, which seeks to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, across industries, and across capital markets. The revenue standard contains principles that an entity will apply to determine the measurement of revenue and timing of when it is recognized. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The amendments are effective prospectively for reporting periods beginning after December 15, 2016 and early adoption is not permitted. The Company is currently assessing the impact on the Company's Consolidated Financial Statements.

In April 2014, the FASB issued Accounting Standards Update (ASU) 2014-08, *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity*, which broadened the reporting of discontinued operations to a component of an entity that has operations and cash flows that can be clearly distinguished from the rest of the entity. Under this guidance, to be a discontinued operation, a component or group of components must represent a strategic shift that has (or will have) a major effect on an entity's operations and financial results. The amendments are effective prospectively for reporting periods beginning on or after December 15, 2014 and early adoption is permitted. The Company chose to early adopt ASU 2014-08 and implemented the amendments during the quarter ended September 30, 2014.

Note 2 - Acquisitions and Divestitures

Permian Basin Acquisition

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, subject to post-closing purchase price adjustments (the Permian Basin Acquisition). The acquired properties consist 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. The acquisition was funded with $50.0 million of restricted cash, $300.0 million from the Company's expanded term loan and the remainder was funded from its revolving credit facility.

The Permian Basin Acquisition meets the definition of a business combination under ASC 805, *Business Combinations*, as it included significant proved properties. QEP allocated the cost of the Permian Basin Acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Revenues of $159.5 million and a net loss of $438.3 million were generated from the acquired properties from February 25, 2014, to December 31, 2014, and are included in QEP's Consolidated Statements of Operations. The net loss is primarily due to an impairment on proved properties of $467.7 million recognized in 2014 due to the decrease in the future oil prices. During the year ended December 31, 2014, QEP Energy incurred acquisition-related costs of $0.6 million, which are included in "General and administrative" on the Consolidated Statement of Operations for the year ended December 31, 2014. QEP incurred $1.1 million of debt issuance costs associated with increasing the size of term loan borrowings to fund a portion of the acquisition, which was subsequently written off when the term loan was repaid in December 2014 with proceeds from the Midstream Sale.

The Consolidated Balance Sheet as of December 31, 2014 includes the Permian Basin Acquisition. The following table presents a summary of the Company's purchase accounting entries:

	As of December 31, 2014
	(in millions)
Consideration:	
Total consideration paid	$ **941.8**
Amounts recognized for fair value of assets acquired and liabilities assumed:	
Proved properties	$ **472.1**
Unproved properties	**480.6**
Asset retirement obligations	**(9.7)**
Liabilities assumed	**(1.2)**
Total fair value	$ **941.8**

The following unaudited, pro forma results of operations are provided for the years ended December 31, 2014 and 2013. These supplemental pro forma results of operations are provided for illustrative purposes only and may not be indicative of the actual results that would have been achieved by the acquired properties for the period presented, or that may be achieved by such properties in the future. Future results may vary significantly from the results reflected in this pro forma financial information because of future events and transactions, as well as other factors. The pro forma information is based on QEP's consolidated results of operations for the years ended December 31, 2014 and 2013, the acquired properties' historical results of operations, and estimates of the effect of the transaction on the combined results. The pro forma results of operations have been prepared by adjusting the historical results of QEP to include the historical results of the acquired properties based on information provided by the seller and the impact of the preliminary purchase price allocation. The pro forma results of operations do not include any cost savings or other synergies that may result from the Permian Basin Acquisition or any estimated costs that have been or will be incurred by the Company to integrate the acquired properties.

	Year ended December 31,			
	2014		2013	
	Actual	**Pro forma**	Actual	Pro forma
	(in millions, except per share data)			
Revenues	$ **3,414.3**	$ **3,440.4**	$ 2,685.1	$ 2,858.8
Net income attributable to QEP	$ **784.4**	$ **791.4**	$ 159.4	$ 195.3
Earnings per common share attributable to QEP				
Basic	$ **4.36**	$ **4.40**	$ 0.89	$ 1.09
Diluted	$ **4.36**	$ **4.40**	$ 0.89	$ 1.09

Williston Basin Acquisition

On September 27, 2012, QEP Energy acquired oil and gas properties in the Williston Basin for an aggregate purchase price of $1.4 billion (the Williston Basin Acquisition). The properties are located in Williams and McKenzie counties of North Dakota, approximately 12 miles west of QEP's then-existing core acreage in the Williston Basin.

The Williston Basin Acquisition meets the definition of a business combination under ASC 805, *Business Combinations,* as it included proved properties. QEP allocated the cost of the Williston Basin Acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Revenues of $767.3 million, $300.0 million and $63.7 million and net income of $402.1 million, $67.0 million and $14.9 million were generated from the acquired properties during the years ended December 31, 2014, 2013 and 2012, respectively, and are included in QEP's Consolidated Statements of Operations. During the year ended December 31, 2012, QEP Energy's acquisition-related costs of $1.1 million are included in "General and administrative" on the Consolidated Statements of Operations.

The following unaudited, pro forma results of operations are provided for the year ended December 31, 2012. These supplemental pro forma results of operations are provided for illustrative purposes only and may not be indicative of the actual results that would have been achieved by the acquired properties for the periods presented, or that may be achieved by such properties in the future. Future results may vary significantly from the results reflected in this pro forma financial information because of future events and transactions, as well as other factors. The pro forma information is based on QEP's consolidated results of operations for the year ended December 31, 2012, the acquired properties' historical results of operations and estimates of the effect of the transaction on the combined results. The pro forma results of operations have been prepared by adjusting the historical results of QEP to include the historical results of the acquired properties based on information provided by the seller and the impact of the purchase price allocation. The pro forma results of operations do not include any cost savings or other synergies that may result from the Williston Basin Acquisition or any estimated costs that have been or will be incurred by the Company to integrate the acquired properties.

	Year ended December 31, 2012	
	Actual	Pro forma
	(in millions, except per share data)	
Revenues	$ 2,071.7	$ 2,207.2
Net income attributable to QEP	$ 128.3	$ 143.0
Earnings per common share attributable to QEP		
Basic	$ 0.72	$ 0.80
Diluted	$ 0.72	$ 0.80

Divestitures

In June 2014, QEP Energy sold its interests in certain non-core properties in the Midcontinent area and other non-core assets in the Williston Basin for aggregate proceeds of $692.9 million, subject to post-closing purchase price adjustments, and recorded a pre-tax loss of $199.4 million. In December 2014, QEP sold its interest in certain non-core properties in southern Oklahoma for aggregate proceeds of $94.9 million, subject to post-closing purchase price adjustments, and recorded a pre-tax gain on sale of $53.3 million.

In June 2013, QEP Energy sold its interests in several non-core oil and gas properties located in QEP's Northern Region for aggregate proceeds of $138.5 million and recorded a pre-tax gain on sale of $96.2 million. In September 2013, QEP Energy sold its interests in several non-core properties located in QEP's Southern Region for aggregate proceeds of $67.3 million and recorded a pre-tax gain on sale of $9.5 million.

These gains and losses are reported on the Consolidated Statements of Operations in "Net gain (loss) from asset sales".

Note 3 - Discontinued Operations

In December 2013, QEP's Board of Directors authorized the Company to develop a plan to separate its midstream business, QEP Field Services, including the Company's interest in QEP Midstream, from QEP. Between December 2013 and September 2014, the Company evaluated transaction alternatives, including selling or merging the midstream business or spinning the midstream business off to its shareholders. In June 2014, QEP filed a registration statement on Form 10 with the U.S. Securities and Exchange Commission (SEC) in preparation for a potential spinoff of QEP Field Services as a separate publicly traded company. Concurrently, the Company evaluated selling or merging its midstream business. In September 2014, based on the proposals received, the Company's Board of Directors authorized QEP's management to engage in the negotiation of terms of a definitive transaction with Tesoro.

In October 2014, the Company announced that its wholly owned subsidiary, QEP Field Services, had entered into a definitive agreement to sell substantially all of its midstream business, including the Company's ownership interest in QEP Midstream. On December 2, 2014, QEP closed the Midstream Sale for total cash proceeds of $2.5 billion, including $230.0 million to refinance debt at QEP Midstream, and QEP recorded a pre-tax gain of $1.8 billion on its Consolidated Statements of Operations in "Net income from discontinued operations, net of income tax" for the year ended December 31, 2014. Subsequent to the Midstream Sale, QEP withdrew its registration statement on Form 10 with the SEC.

As of December 31, 2014, the operating results of QEP Field Services, excluding the Haynesville Gathering System, were classified as discontinued operations on its Consolidated Statements of Operations. QEP will have continuing cash outflows to the entities sold as a part of the Midstream Sale for gathering, processing and water handling costs in Pinedale, the Uinta Basin and a portion of its Williston Basin operations. The contracts related to these cash flows vary in length from month-to-month to over a year and will be reviewed periodically in the normal course of business. Historically, these transactions were eliminated in consolidation, as they represented transactions between two related entities but are now reflected as part of the continuing operations for QEP. For the years ended December 31, 2014, 2013 and 2012, cash outflows for these transactions included in continuing operations were $145.3 million, $124.6 million and $113.5 million, respectively.

Consolidated Statement of Operations

The discontinued operations of QEP Field Services (excluding results of the Haynesville Gathering System) are summarized below:

	Year Ended December 31,		
	2014	2013	2012
	(in millions)		
REVENUES			
NGL sales	**$ 109.3**	$ 101.9	$ 137.9
Other revenues	**140.9**	166.6	154.1
Purchased gas, oil and NGL sales[1]	**(47.1)**	(17.8)	(13.9)
Total Revenues	**203.1**	250.7	278.1
OPERATING EXPENSES			
Purchased gas, oil and NGL expense[1]	**(48.5)**	(17.6)	(15.1)
Lease operating expense[1]	**(5.5)**	(3.5)	(3.5)
Natural gas, oil and NGL transport & other handling costs[1]	**(55.4)**	(80.6)	(49.2)
Gathering, processing, and other	**85.9**	82.2	79.8
General and administrative	**42.1**	30.7	17.9
Production and property taxes	**7.3**	5.2	5.1
Depreciation, depletion and amortization	**45.9**	52.2	55.1
Total Operating Expenses	**71.8**	68.6	90.1
Net gain (loss) from asset sales	**1,793.4**	(0.5)	—
OPERATING INCOME	**1,924.7**	181.6	188.0
Realized derivative gains	**—**	—	8.4
Interest and other income (expense)	**0.3**	(10.0)	(8.2)
Income from unconsolidated affiliates	**4.9**	5.6	6.7
Loss on early extinguishment of debt	**(2.4)**	—	—
Interest expense (income)	**(3.8)**	1.8	3.4
INCOME FROM DISCONTINUED OPERATIONS BEFORE INCOME TAXES [2]	**1,923.7**	179.0	198.3
Income tax provision	**(708.2)**	(59.7)	(68.7)
NET INCOME FROM DISCONTINUED OPERATIONS	**1,215.5**	119.3	129.6
Net income attributable to noncontrolling interest	**(21.6)**	(12.0)	(3.7)
NET INCOME FROM DISCONTINUED OPERATIONS, NET OF INCOME TAX	**$ 1,193.9**	$ 107.3	$ 125.9

(1) Includes discontinued intercompany eliminations.
(2) Includes income from discontinued operations before income taxes attributable to QEP from QEP Midstream (of which QEP owned 57.8%) of $28.9 million, $33.5 million and $38.9 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Consolidated Balance Sheet

The current and noncurrent assets and liabilities of QEP Field Services (excluding the retained Haynesville Gathering System) are as follows:

	December 31, 2013	
Cash and cash equivalents	$	18.1
Accounts receivable, net		53.9
Income taxes receivable		38.4
Deferred income taxes - current		2.7
Prepaid expenses and other		8.9
Current assets of discontinued operations	$	122.0
Property, Plant and Equipment		
Midstream field services	$	1,500.8
Material and supplies		4.8
Total Property, Plant and Equipment		1,505.6
Less Accumulated Depreciation, Depletion and Amortization		(381.6)
Net Property, Plant and Equipment		1,124.0
Investment in unconsolidated affiliates		39.0
Other noncurrent assets		4.7
Noncurrent assets of discontinued operations	$	1,167.7
Accounts payable and accrued expenses	$	74.1
Production and property taxes		1.2
Current liabilities of discontinued operations	$	75.3
Deferred income taxes	$	195.7
Asset retirement obligations		28.5
Other long-term liabilities		14.1
Noncurrent liabilities of discontinued operations	$	238.3

Consolidated Statement of Cash Flows

The impact of QEP Field Services discontinued operations (excluding the Haynesville Gathering System) on the Consolidated Statements of Cash Flows for "Depreciation, depletion and amortization" contained in "Cash flows from operating activities" was $45.9 million, $52.2 million and $55.1 million for the years ended December 31, 2014, 2013, and 2012, respectively. The impact on cash used for "Property, plant and equipment, including dry hole exploratory well expense" contained in "Cash flows from investing activities" was $55.2 million, $88.9 million and $156.2 million for the years ended December 31, 2014, 2013, and 2012, respectively.

Note 4 - Capitalized Exploratory Well Costs

Net changes in capitalized exploratory well costs are presented in the table below. The balances at December 31, 2014, 2013 and 2012, represent the amount of capitalized exploratory well costs that are pending the determination of proved reserves.

	2014	2013	2012
	(in millions)		
Balance at January 1,	**$ 2.6**	$ 2.1	$ 5.0
Additions to capitalized exploratory well costs pending the determination of proved reserves	**13.7**	2.7	12.7
Reclassifications to proved properties after the determination of proved reserves	**—**	(2.2)	(15.6)
Capitalized exploratory well costs charged to expense	**(3.7)**	—	—
Balance at December 31,	**$ 12.6**	$ 2.6	$ 2.1

Note 5 - Asset Retirement Obligations

QEP records asset retirement obligations when there are legal obligations associated with the retirement of tangible long-lived assets. The Company's ARO liability applies primarily to abandonment costs associated with oil and gas wells and certain other properties. The fair values of such costs are estimated by Company personnel based on abandonment costs of similar assets and depreciated over the life of the related assets. Revisions to the ARO estimates result from changes in expected cash flows or material changes in estimated asset retirement costs. The ARO liability is adjusted to present value each period through an accretion calculation using a credit-adjusted risk-free interest rate. Of the $195.1 million and $165.1 million ARO liability for the years ended December 31, 2014 and 2013, respectively, $1.3 million and $1.8 million was included as a liability in "Accounts payable and accrued expenses" on the Consolidated Balance Sheets.

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

	Asset Retirement Obligations	
	2014	2013
	(in millions)	
ARO liability at January 1,[1]	**$ 165.1**	$ 155.6
Accretion	**6.7**	5.6
Additions[2]	**17.1**	6.9
Revisions	**33.6**	11.8
Liabilities related to assets sold	**(24.7)**	(11.8)
Liabilities settled	**(2.7)**	(3.0)
ARO liability at December 31,	**$ 195.1**	$ 165.1

(1) Excludes $28.5 million and $37.5 million of ARO as of January 1, 2014 and 2013, respectively, classified as "Noncurrent liabilities of discontinued operations" on the Consolidated Balance Sheets.

(2) Additions include $9.7 million related to the Permian Basin Acquisition (see Note 2 - Acquisitions and Divestitures).

Note 6 - Fair Value Measurements

QEP measures and discloses fair values in accordance with the provisions of ASC 820, *Fair Value Measurements and Disclosures*. This guidance defines fair value in applying GAAP, establishes a framework for measuring fair value and expands disclosures about fair-value measurements, but does not change existing guidance as to whether or not an instrument is carried at fair value. ASC 820 also establishes a fair-value hierarchy. Level 1 inputs are quoted prices (unadjusted) for identical assets or liabilities in active markets that the Company has the ability to access at the measurement date. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the asset or liability.

QEP has determined that its commodity derivative instruments are Level 2. The Level 2 fair value of commodity derivative contracts (see Note 7 - Derivative Contracts) is based on market prices posted on the respective commodity exchange on the last trading day of the reporting period and industry standard discounted cash flow models. QEP primarily applies the market approach for recurring fair value measurements and maximizes its use of observable inputs and minimizes its use of unobservable inputs. QEP considers bid and ask prices for valuing the majority of its assets and liabilities measured and reported at fair value. In addition to using market data, QEP makes assumptions in valuing its assets and liabilities, including assumptions about risk and the risks inherent in the inputs to the valuation technique. The Company's policy is to recognize significant transfers between levels at the end of the reporting period.

Certain of the Company's commodity derivative instruments are valued using industry standard models that consider various inputs, including quoted forward prices for commodities, time value, volatility, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument and can be derived from observable data or are supported by observable prices at which transactions are executed in the marketplace. The determination of fair value for derivative assets and liabilities also incorporates nonperformance risk for counterparties and for QEP. Derivative contract fair values are reported on a net basis to the extent a legal right of offset with the counterparty exists.

In addition, during 2013 QEP had interest rate swaps that it determined were Level 2 financial instruments. As of December 31, 2014, the interest rate swaps were terminated. The fair values of the interest rate swaps were determined using the market standard methodology of discounting the future expected cash flows that would occur under the contractual terms of the swap. The variable interest rates used in the calculation of projected cash flows were based on an expectation of future interest rates derived from observable market interest rate curves. QEP incorporated credit valuation adjustments to reflect both its nonperformance risk and the respective counterparty's nonperformance risk in the fair value measurements. While the credit valuation adjustments were not observable inputs, they were not significant to the overall valuation and the other inputs used to value the interest rate swaps were observable Level 2 inputs.

The fair value of financial assets and liabilities at December 31, 2014 and 2013, is shown in the tables below:

	Fair Value Measurements December 31, 2014				
	Gross Amounts of Assets and Liabilities				
	Level 1	**Level 2**	**Level 3**	**Netting Adjustments**[1]	**Net Amounts Presented on the Consolidated Balance Sheet**
	(in millions)				
Financial Assets					
Commodity derivative instruments - short-term	$ —	$ 339.3	$ —	$ (0.3)	$ 339.0
Commodity derivative instruments - long-term	—	9.9	—	—	9.9
Total financial assets	$ —	$ 349.2	$ —	$ (0.3)	$ 348.9
Financial Liabilities					
Commodity derivative instruments - short-term	$ —	$ 0.3	$ —	$ (0.3)	$ —
Total financial liabilities	$ —	$ 0.3	$ —	$ (0.3)	$ —

(1) The Company nets its derivative contract assets and liabilities outstanding with the same counterparty on the Consolidated Balance Sheets for the contracts that contain netting provisions. Refer to Note 7 - Derivative Contracts, for additional information regarding the Company's derivative contracts.

	Fair Value Measurements December 31, 2013				
	Gross Amounts of Assets and Liabilities				
	Level 1	Level 2	Level 3	Netting Adjustments[1]	Net Amounts Presented on the Consolidated Balance Sheet
	(in millions)				
Financial Assets					
Commodity derivative instruments - short-term	$ —	$ 5.5	$ —	$ (5.3)	$ 0.2
Commodity derivative instruments - long-term	—	0.4	—	—	0.4
Interest rate swaps - long-term	—	0.6	—	—	0.6
Total financial assets	$ —	$ 6.5	$ —	$ (5.3)	$ 1.2
Financial Liabilities					
Commodity derivative instruments - short-term	$ —	$ 29.4	$ —	$ (5.3)	$ 24.1
Interest rate swaps - short-term	—	2.6	—	—	2.6
Total financial liabilities	$ —	$ 32.0	$ —	$ (5.3)	$ 26.7

(1) The Company nets its derivative contract assets and liabilities outstanding with the same counterparty on the Consolidated Balance Sheets for the contracts that contain netting provisions. Refer to Note 7 - Derivative Contracts, for additional information regarding the Company's derivative contracts.

The following table discloses the fair value and related carrying amount of certain financial instruments not disclosed in other Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K:

	Carrying Amount	**Level 1 Fair Value**	Carrying Amount	Level 1 Fair Value
	December 31, 2014		December 31, 2013	
	(in millions)			
Financial assets				
Cash and cash equivalents	**$ 1,160.1**	**$ 1,160.1**	$ 11.9	$ 11.9
Financial liabilities				
Checks outstanding in excess of cash balances	**$ 54.7**	**$ 54.7**	$ 109.1	$ 109.1
Long-term debt	**2,218.1**	**$ 2,171.6**	2,997.5	$ 3,034.9

The carrying amounts of cash and cash equivalents and checks outstanding in excess of cash balances approximate fair value. The fair value of fixed-rate long-term debt is based on the trading levels and dollar prices for the Company's debt at the end of the year. The carrying amount of variable-rate long-term debt approximates fair value because the floating interest rate paid on such debt was set for periods of one month.

The initial measurement of ARO at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with property, plant and equipment. Significant Level 3 inputs are used in the calculation of ARO including plugging cost estimates and reserve lives. A reconciliation of the Company's asset retirement obligations is presented in Note 5 - Asset Retirement Obligations.

Nonrecurring Fair Value Measurements

The provisions of the fair value measurement standard are also applied to the Company's nonrecurring, non-financial measurements. The Company utilizes fair value on a non-recurring basis to review its proved oil and gas properties for potential impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such property. During the years ended December 31, 2014 and 2013, the Company recorded impairments on certain oil and gas properties resulting in a write down of the associated carrying value to fair value. The fair value of the property was measured utilizing the income approach and utilizing inputs which are primarily based upon internally developed cash flow models. Given the unobservable nature of the inputs, proved oil and gas property impairments are considered Level 3 within the fair value hierarchy. During the years ended December 31, 2014 and 2013, the Company recorded $1,041.4 million and $1.2 million, respectively, of impairments related to certain of its proved properties. The proved properties were written down to their estimated fair values at the time of the impairments during December 31, 2014 and 2013, respectively.

Acquisitions of proved and unproved properties are also measured at fair value on a nonrecurring basis. The Company utilized a discounted cash flow model to estimate the fair value of acquired property as of the acquisition date which utilized the following inputs to estimate future net cash flows: estimated quantities of oil, gas and NGL reserves; estimates of future commodity prices; and estimated production rates, future operating and development costs, which were based on the Company's historic experience with similar properties. In some instances, market comparable information of recent transactions is used to estimate fair value of unproved acreage. Due to the unobservable characteristics of the inputs, the fair value of the properties is considered Level 3 within the fair value hierarchy. Refer to Note 2 - Acquisitions and Divestitures for additional information on the fair value of acquired properties.

Note 7 - Derivative Contracts

QEP has established policies and procedures for managing commodity price volatility through the use of derivative instruments. In the normal course of business, QEP uses commodity price derivative instruments to reduce the impact of potential downward movements in commodity prices on cash flow, returns on capital investment, and other financial results. However, these instruments typically limit gains from favorable price movements. The volume of production subject to commodity derivative instruments and the mix of the instruments are frequently evaluated and adjusted by management in response to changing market conditions. QEP may enter into commodity derivative contracts for up to 100% of forecasted production from proved reserves. In addition, QEP may enter into commodity derivative contracts on a portion of its gas sales and purchases for marketing transactions. QEP does not enter into commodity derivative instruments for speculative purposes.

QEP uses commodity derivative instruments known as fixed-price swaps or collars to realize a known price or price range for a specific volume of production delivered into a regional sales point. QEP's commodity derivative instruments do not require the physical delivery of gas, oil, or NGL between the parties at settlement. Swap transactions are settled in cash with one party paying the other for the net difference in prices, multiplied by the contract volume, for the settlement period. Gas price derivative instruments are typically structured as fixed-price swaps at regional price indices. Oil price derivative instruments are typically structured as NYMEX fixed-price swaps based at Cushing, Oklahoma or oil price swaps that use Intercontinental Exchange, Inc. (ICE) Brent oil prices as the reference price. QEP also enters into crude oil basis swaps to achieve a fixed price swap for a portion of its oil it sells at prices that reference ICE Brent and Light Louisiana Sweet (LLS).

QEP enters into commodity derivative transactions that do not have margin requirements or collateral provisions that would require payments prior to the scheduled settlement dates. Commodity derivative contract counterparties are normally financial institutions and energy trading firms with investment-grade credit ratings. QEP routinely monitors and manages its exposure to counterparty risk by requiring specific minimum credit standards for all counterparties and avoids concentration of credit exposure by transacting with multiple counterparties.

Effective January 1, 2012, QEP elected to de-designate all of its gas, oil and NGL derivative contracts that were previously designated as cash flow hedges and discontinue hedge accounting prospectively. As a result of discontinuing hedge accounting, the mark-to-market values at December 31, 2011, were fixed in AOCI as of the de-designation date and reclassified into the Consolidated Statement of Operations as the transactions settled and affected earnings. QEP fully reclassified all unrealized gains in AOCI into earnings during 2012 and 2013. All realized and unrealized gains and losses from derivative instruments incurred after January 1, 2012, are presented in the Consolidated Statements of Operations in "Realized and unrealized gains (losses) on derivative contracts" below operating income.

QEP also used interest rate swaps to mitigate a portion of its exposure to interest rate volatility risk associated with QEP's former $600.0 million term loan. For the $300.0 million term loan issued during 2012, QEP locked in a fixed interest rate of 1.07% in exchange for a variable interest rate indexed to the one-month LIBOR. For the incremental $300.0

million borrowed under the term loan during 2014, QEP locked in a fixed interest rate of 0.86%. The average effective interest rate on the $600.0 million term loan when combined with the fixed interest rate swaps for the year ended December 31, 2014, was 3.24%. These interest rate swaps were terminated in December 2014 along with the extinguishment of QEP's term loan.

QEP Energy's Derivative Contracts

The following table sets forth QEP Energy's quantities and average prices for its commodity derivative contracts as of December 31, 2014:

Year	Type of Contract	Index	Total Volumes	Swaps Average price per unit
			(in millions)	
Gas sales			**(MMBtu)**	
2015	Swap	NYMEX HH	29.2	$ 4.11
2015	Swap	IFNPCR	40.2	$ 3.70
Oil sales			**(Bbls)**	
2015	Swap	NYMEX WTI	7.7	$ 90.04
2015	Swap	ICE Brent	0.4	$ 104.95
2016	Swap	NYMEX WTI	0.4	$ 90.00

The following table sets forth QEP Energy's crude oil sales costless collars as of December 31, 2014:

Year	Index	Total Volume Bbls	Average Price Floor	Average Price Ceiling
		(in millions)		
2015	NYMEX WTI	0.5	$ 50.00	$ 63.34

The following table sets forth QEP Energy's oil basis swaps as of December 31, 2014:

Year	Index	Index Less Differential	Total Volumes Bbls	Weighted Average Differential
Oil basis swaps			(in millions)	
2015	NYMEX WTI	LLS	0.1	$ 4.03

QEP Marketing Derivative Contracts

QEP Marketing enters into commodity derivative transactions to lock in a margin on gas volumes placed into storage and for marketing transactions in which QEP Marketing sells gas volumes at a fixed price. The following table sets forth QEP Marketing's volumes and swap prices for its commodity derivative contracts as of December 31, 2014:

Year	Type of Contract	Index	Total Volumes	Average Swap price per MMBtu
			(in millions)	
Gas sales			**(MMBtu)**	
2015	Swap	IFNPCR	2.8	$ 4.03
2016	Swap	IFNPCR	0.9	$ 3.58
Gas purchases			**(MMBtu)**	
2015	Swap	IFNPCR	0.9	$ 3.06

QEP Derivative Financial Statement Presentation

The following table presents the balance sheet location of QEP's outstanding derivative contracts on a gross contract basis as opposed to the net contract basis presentation in the Consolidated Balance Sheets and the related fair values at the balance sheet dates:

		Gross asset derivative instruments fair value		Gross liability derivative instruments fair value	
		December 31,			
	Balance Sheet line item	**2014**	2013	**2014**	2013
		(in millions)		(in millions)	
Current:					
Commodity	Fair value of derivative contracts	**$ 339.3**	$ 5.5	**$ 0.3**	$ 29.4
Interest rate swaps	Fair value of derivative contracts	**—**	—	**—**	2.6
Long-term:					
Commodity	Fair value of derivative contracts	**9.9**	0.4	**—**	—
Interest rate swaps	Fair value of derivative contracts	**—**	0.6	**—**	—
Total derivative instruments		**$ 349.2**	$ 6.5	**$ 0.3**	$ 32.0

The effects of the change in fair value and settlement of QEP's derivative contracts recorded in "Realized and Unrealized gains on derivatives" on the Consolidated Statements of Operations are summarized in the following tables:

Derivative instruments not designated as cash flow hedges	Year Ended December 31, **2014**	2013	2012
Realized gains (losses) on commodity derivative contracts		(in millions)	
QEP Energy			
Gas derivative contracts	**$ (16.7)**	$ 152.0	$ 341.9
Oil derivative contracts	**15.7**	(2.2)	14.4
NGL derivative contracts	**—**	—	10.2
QEP Marketing			
Gas derivative contracts	**(2.5)**	0.5	5.1
Total realized gains (losses) on commodity derivative contracts	**(3.5)**	150.3	371.6
Unrealized gains (losses) on commodity derivative contracts			
QEP Energy			
Gas derivative contracts	**68.4**	(42.6)	37.8
Oil derivative contracts	**299.8**	(48.1)	29.0
NGL derivative contracts	**—**	—	1.6
QEP Marketing			
Gas derivative contracts	**4.2**	(2.1)	0.9
Total unrealized gains (losses) on commodity derivative contracts	**372.4**	(92.8)	69.3
Total realized and unrealized gains (losses) on commodity derivative contracts	**$ 368.9**	$ 57.5	$ 440.9
Realized gains (losses) on interest rate swaps			
Realized losses on interest rate swaps	**$ (7.6)**	$ (2.7)	$ (1.3)
Unrealized gains (losses) on interest rate swaps			
Unrealized gains (losses) on interest rate swaps	**2.0**	4.1	(6.1)
Total realized and unrealized gains (losses) on interest rate swaps	**(5.6)**	1.4	(7.4)
Total net realized gains (losses) on derivative contracts	**(11.1)**	147.6	370.3
Total net unrealized gains (losses) on derivative contracts	**374.4**	(88.7)	63.2
Grand Total	**$ 363.3**	$ 58.9	$ 433.5

Note 8 - Restructuring Costs

In December 2013, QEP announced its plan to pursue a separation of its midstream business, QEP Field Services. In connection with this announcement, the Board of Directors approved an employee retention plan to provide substantially all QEP Field Services' employees as of December 1, 2013, with a one-time lump-sum cash payment on the earlier of December 31, 2014, or whenever the separation of QEP Field Services occurs, conditioned on continued employment with QEP Field Services or a successor through the payment date unless the employee is terminated prior to such date. In December 2014, QEP paid the retention bonus to eligible employees in connection with the Midstream Sale. QEP recognized $10.4 million of costs under this retention plan, which is included in "Discontinued operations, net of income tax" on the Consolidated Statements of Operations.

During 2012, QEP began incurring costs related to the closure of its Oklahoma City office and the subsequent consolidation of its Southern Region operations into a single regional office located in Tulsa. Additionally, during 2012, QEP began incurring additional restructuring and reorganization costs related to consolidating various corporate and accounting functions to the Denver corporate headquarters. The creation of one office for QEP’s Southern Region as well as the consolidation of corporate and accounting functions increased efficiency, team-based collaboration and organizational productivity. As part of the reorganization, QEP incurred costs associated with the severance, retention and relocation of employees, additional pension expenses, exit costs associated with the termination of operating leases arising from office space that will no longer be utilized by the Company and other expenses. All restructuring costs related to the 2012 office consolidations and continued operations were incurred and settled by December 31, 2013.

The following table summarizes, by line of business, each major type of restructuring cost expected to be incurred and the total amounts recorded in "General and administrative" expense on the Consolidated Statements of Operations for the respective periods indicated:

	Total Expected to be Incurred	Total Restructuring Costs Recognized in Income: Period from Inception to December 31, 2014	Year ended December 31, 2014	2013	2012
Continuing Operations:	(in millions)				
QEP Energy					
One-time termination benefits	$ 3.3	$ 3.3	$ —	$ 0.4	$ 2.9
Retention & relocation expense	3.7	3.7	—	0.4	3.3
Lease termination costs	0.6	0.6	—	—	0.6
Total restructuring costs	$ 7.6	$ 7.6	$ —	$ 0.8	$ 6.8
QEP Marketing and Other					
One-time termination benefits	$ 0.3	$ 0.3	$ —	$ 0.1	$ 0.2
Total restructuring costs	$ 0.3	$ 0.3	$ —	$ 0.1	$ 0.2
Total QEP					
One-time termination benefits	$ 3.6	$ 3.6	$ —	$ 0.5	$ 3.1
Retention & relocation expense	3.7	3.7	—	0.4	3.3
Lease termination costs	0.6	0.6	—	—	0.6
Total restructuring costs	$ 7.9	$ 7.9	$ —	$ 0.9	$ 7.0

Note 9 - Debt

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

	December 31, 2014	2013
	(in millions)	
Revolving Credit Facility due 2019	**$ —**	$ 480.0
Term Loan due 2017	**—**	300.0
6.05% Senior Notes due 2016	**176.8**	176.8
6.80% Senior Notes due 2018	**134.0**	134.0
6.80% Senior Notes due 2020	**136.0**	136.0
6.875% Senior Notes due 2021	**625.0**	625.0
5.375% Senior Notes due 2022	**500.0**	500.0
5.25% Senior Notes due 2023	**650.0**	650.0
Total principal amount of debt	**2,221.8**	3,001.8
Less unamortized discount	**(3.7)**	(4.3)
Total long-term debt outstanding	**$ 2,218.1**	$ 2,997.5

Of the total debt outstanding on December 31, 2014, the 6.05% Senior Notes due September 1, 2016, and the 6.80% Senior Notes due April 1, 2018 will mature within the next five years. The revolving credit facility matures on December 2, 2019.

QEP's Credit Facility

QEP’s unsecured revolving credit facility, which matures in December 2019, provides for loan commitments of $1.8 billion from a group of financial institutions. The credit facility provides for borrowings at short-term interest rates and contains customary covenants and restrictions.

On December 2, 2014, QEP entered into the Fourth Amendment to its Credit Agreement, which increased the aggregate principal amount of commitments to $1.8 billion, extended the maturity date to December 2, 2019, and made minor adjustments to other provisions and covenants.

During the years ended December 31, 2014 and 2013, QEP's weighted-average interest rates on borrowings from its credit facility were 2.23% and 2.22%, respectively. At December 31, 2014, QEP had no borrowings outstanding and had $3.7 million in letters of credit outstanding under the credit facility. At December 31, 2013, QEP had $480.0 million outstanding and QEP had $3.8 million in letters of credit outstanding under the credit facility. At December 31, 2014 and 2013, QEP was in compliance with the covenants under the credit facility.

Term Loan

On December 2, 2014, QEP repaid and terminated its $600.0 million term loan with a portion of the proceeds from the Midstream Sale. The term loan facility provided borrowings at short-term interest rates and contained covenants, restrictions and interest rates that were substantially the same as QEP’s revolving credit facility. During the years ended December 31, 2014 and 2013, QEP's weighted-average interest rates on borrowings from the term loan were 2.28% and 2.22%, respectively.

Senior Notes

At December 31, 2014, the Company had $2,221.8 million principal amount of senior notes outstanding with maturities ranging from September 2016 to May 2023 and coupons ranging from 5.25% to 6.875%. The senior notes pay interest semi-annually, are unsecured senior obligations and rank equally with all of our other existing and future unsecured and senior obligations. QEP may redeem some or all of its senior notes at any time before their maturity at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption. The indentures governing QEP's senior notes contain customary events of default and covenants that may limit QEP's ability to, among other things, place liens on its property or assets.

Note 10 - Commitments and Contingencies

QEP is involved in various commercial and regulatory claims, litigation and other legal proceedings that arise in the ordinary course of its business. QEP assesses these claims in an effort to determine the degree of probability and range of possible loss for potential accrual in its Consolidated Financial Statements. In accordance with ASC 450, Contingencies, an accrual is recorded for a loss contingency when its occurrence is probable and damages are reasonably estimable based on the anticipated most likely outcome or the minimum amount within a range of possible outcomes. Because legal proceedings are inherently unpredictable, and unfavorable resolutions can occur, assessing contingencies is highly subjective and requires judgments about uncertain future events. When evaluating contingencies, QEP may be unable to provide a meaningful estimate due to a number of factors, including the procedural status of the matter in question, the presence of complex or novel legal theories, the ongoing discovery and/or development of information important to the matter. QEP's litigation loss contingencies are discussed below. Except for the Rocky Mountain Resources matter discussed below, QEP is unable to estimate reasonably possible losses (in excess of recorded accruals, if any) for these contingencies for the reasons set forth above. QEP believes, however, that the resolution of pending proceedings (after accruals, insurance coverage, and indemnification arrangements) will not be material to QEP's financial position, but could be material to results of operations in a particular quarter or year.

Environmental Claims

In October 2009, QEP received a cease and desist order from the U.S. Army Corps of Engineers (COE) to refrain from unpermitted work resulting in the discharge of dredged and/or fill material into waters of the United States at three sites located in Caddo and Red River Parishes, Louisiana. Region 6 of the U.S. Environmental Protection Agency (EPA) has assumed lead responsibility for enforcement of the cease and desist order and any possible future orders for the removal of unauthorized fills and/or civil penalties under the Clean Water Act. On June 28, 2013, the EPA issued to QEP an Administrative Complaint for the alleged violations. QEP and the EPA reached an agreement to settle the alleged violations through an Administrative Order, under the terms of which QEP paid an administrative penalty of $0.2 million. The Administrative Order is final. In 2012, QEP completed a field audit, which identified 112 additional instances affecting approximately 90 acres where work may have been conducted in violation of the Clean Water Act. QEP has disclosed each of these instances to the EPA under the EPA's Audit Policy (to reduce penalties) and to the COE. QEP is working with the EPA and the COE to resolve these matters, which will require the Company to undertake certain mitigation and permitting activities, and may require QEP to pay a monetary penalty.

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

Litigation

Rocky Mountain Resources, LLC v. QEP Energy Company, Wexpro Company, Ultra Resources, Inc. and Lance Oil & Gas Company, Inc., Civil No. 2011-7816, District Court of Sublette County, Wyoming. Rocky Mountain Resources, LLC (Rocky Mountain) filed its complaint on March 30, 2011, seeking determination of the existence of a 4% overriding royalty interest in State of Wyoming oil and gas Lease No. 79-0645 covering Section 16, T32-N R-109-W, Sublette County, Wyoming. QEP and the other defendants are current lessees of Lease 79-0645. Rocky Mountain alleges that the defendants have received benefits from Lease 79-0645 and have failed to pay Rocky Mountain monies associated with the claimed 4% overriding royalty interest since the issuance of the lease by the State of Wyoming in 1980. Rocky Mountain asserts claims for quiet title, declaratory judgment, breach of contract, breach of duty of good faith, conversion, constructive trust and prejudgment interest. On May 7, 2014, the trial court entered its order granting plaintiff's motion for summary judgment on the issue of whether the overriding royalty interest burdens QEP's lease. On June 17, 2014, the Supreme Court of Wyoming denied QEP's Petition for Writ of Review. On August 21, 2014, the trial court denied QEP’s Motion to Certify Questions of Law to the Wyoming Supreme Court. At the conclusion of a trial in February 2015, and after being instructed by the Court that the overriding royalty interest burdened QEP’s lease, a jury rendered a verdict against QEP and awarded Rocky Mountain damages in the amount of $16.7 million, including interest. QEP believes that the Court’s ruling on summary judgment and the resulting jury instructions are in error and will appeal to the Wyoming Supreme Court. While the appeal is pending, post-judgment interest accrues at the statutory rate of 10%. QEP estimates that, notwithstanding the verdict, the range of reasonably possible losses is still zero to $20 million.

Gatti et al v. State of Louisiana et al, 589,350, 19th JDC, Parish of East Baton Rouge, Louisiana. In this putative class action arising out of the unitization practices and orders of the Louisiana Commissioner of Conservation (Commissioner), plaintiffs seek to represent a class of all Haynesville Shale mineral owners (alleged to be over 50,000 in number) against the Commissioner and all Haynesville Shale unit operators. Plaintiffs filed their complaint on April 8, 2010, and claim that the Commissioner exceeded his statutory authority in creating and perpetuating units larger than the area that can be efficiently and economically drained by a single well. They seek declaratory relief that would nullify all such improper orders, along with an unspecified amount of monetary damages from the unit operators sufficient to compensate the putative class members for the alleged dilution of their true interest in unit production as a result of "oversized" units and the "cloud on title" caused by having excessive and improperly sized units purport to hold their mineral leases via unit operations. All defendants filed exceptions to the plaintiffs' petition on the primary ground that plaintiffs had failed to comply with the exclusive statutory judicial review procedure (Louisiana Revised Statutes 30:12), which the trial court granted, dismissing the action in its entirety. On January 15, 2014, the Louisiana First Circuit Court of Appeal reversed and reinstated plaintiffs' claims. Defendants asked for review by the Louisiana Supreme Court and on August 25, 2014, the Supreme Court reversed the Court of Appeals and dismissed the plaintiffs’ claim without prejudice as originally ordered by the District Court.

Yannick Gagné and others similarly situated v. QEP Resources, Inc., No. 480-06-1-132, Superior Court, Province of Quebec, Canada. Plaintiffs seek to represent a class of all 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 fourth amended motion to authorize the bringing of a class action was filed on February 19, 2014, and names numerous defendants. The plaintiffs contend 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, knowingly added volatile light end petroleum liquids and/or vapors or blended the crude with condensate, failed to conduct adequate well site testing to determine the proper hazard classification of the oil, failed to properly classify the shipping requirements for the oil, failed to take reasonable care to ensure that the oil was properly labeled and shipped, failed to identify the risk of the train derailment and take action to prevent it, and failed to adopt, implement and enforce rules and procedures pertaining to the safe shipment of the oil. The plaintiffs seek damages, but specific monetary damages are not asserted. Class certification hearings took place in June 2014, and a court order regarding class certification is pending.

Litigation related to discontinued operations:

In accordance with the terms of the Membership Interest Purchase Agreement, dated October 19, 2014, by and between QEP Field Services and Tesoro, Tesoro agreed to assume the defense of, and indemnify, defend and hold harmless QEP Field Services and its affiliates, including QEP, from and against all liability, loss, cost, expense, claim, award or judgment associated with the following litigation matters previously disclosed: *Questar Gas Company v. QEP Field Services Company* and *XTO Energy Inc. v. QEP Field Services Company*. Therefore, in light of Tesoro's indemnification obligations and after assessing Tesoro's ability to satisfy its indemnification obligations, QEP believes it is not reasonably likely to have liability for these matters.

Commitments

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

Year		Amount
2015	$	130.7
2016	$	120.6
2017	$	120.0
2018	$	117.1
2019	$	112.0
After 2019	$	407.4

QEP rents office space throughout its scope of operations from third-party lessors. Rental expense from operating leases amounted to $8.2 million, $7.8 million, and $7.3 million during the years ended December 31, 2014, 2013 and 2012, respectively. Minimum future payments under the terms of long-term operating leases for the Company's primary office locations are as follows (in millions):

	Year	Amount
2015	$	8.4
2016	$	8.2
2017	$	8.4
2018	$	6.9
2019	$	6.8
After 2019	$	23.9

Note 11 - Equity-Based Compensation

QEP issues stock options and restricted shares under its LTSIP and awards performance share units under its CIP to certain officers, employees, and non-employee directors. QEP recognizes expense over time as the stock options, restricted shares, and performance share units vest. Deferred equity-based compensation is included in additional paid-in capital in the Consolidated Balance Sheets. There were 10.8 million shares available for future grants under the LTSIP at December 31, 2014. Equity-based compensation expense is recognized in "General and administrative" on the Consolidated Statements of Operations, and expenses related to discontinued operations (including compensation expense related to the QEP Midstream Long Term Incentive Plan) are reflected in "Discontinued operations, net of income tax". During the year ended December 31, 2014 for continuing operations, QEP recognized $21.4 million in total compensation expense related to equity-based compensation compared to $25.7 million and $25.6 million during the years ended December 31, 2013 and 2012, respectively. For discontinued operations during the year ended December 31, 2014, QEP recognized $5.8 million in total compensation expense related to equity based compensation, compared to $1.4 million during the year ended December 31, 2013.

Stock Options

QEP uses the Black-Scholes-Merton mathematical model to estimate the fair value of stock option awards at the date of the grant. Fair-value calculations rely upon subjective assumptions used in the mathematical model and may not be representative of future results. The Black-Scholes-Merton model is intended for measuring the value of options traded on an exchange. The Company utilizes the "simplified" method to estimate the expected term of the stock options granted as there is limited historical exercise data available in estimating the expected term of the stock options. QEP uses a historical volatility method to estimate the fair value of stock options awards and the risk-free interest rate is based on the yield on U.S. Treasury strips with maturities similar to those of the expected term of the stock options. The stock options typically vest in equal installments over a three-year period from the grant date and are exercisable immediately upon vesting through the seventh anniversary of the grant date. To fulfill options exercised, QEP either reissues treasury stock or issues new shares.

The calculated fair value of options granted and major assumptions used in the model at the date of grant are listed below:

	Stock Option Variables		
	Year Ended December 31,		
	2014	2013	2012
Weighted-average grant-date fair value of awards granted during the period	**$ 10.11**	$ 15.16	$ 14.29
Risk-free interest rate range	**1.31% - 1.34%**	0.97% - 1.84%	0.63% - 1.04%
Weighted-average risk-free interest rate	**1.3%**	1.0%	0.8%
Expected price volatility range	**36.1% - 37.3%**	51.5% - 58.5%	55.9% - 56.5%
Weighted-average expected price volatility	**37.1%**	58.3%	55.9%
Expected dividend yield	**0.25%**	0.27%	0.26%
Expected term in years at the date of grant	**4.5**	5.5	5.0

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

	Options Outstanding	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
		(per share)	(in years)	(in millions)
Outstanding at December 31, 2013	1,794,187	$ 27.90		
Granted	**282,236**	**31.67**		
Exercised	**(65,366)**	**22.24**		
Forfeited	**(14,842)**	**30.53**		
Outstanding at December 31, 2014	**1,996,215**	**$ 28.60**	**3.18**	**$ 0.1**
Options Exercisable at December 31, 2014	**1,494,061**	**$ 27.80**	**2.39**	**$ 0.1**
Unvested Options at December 31, 2014	**502,154**	**$ 30.98**	**5.51**	**$ —**

The total intrinsic value (the difference between the market price at the exercise date and the exercise price) of options exercised was $0.6 million, $4.3 million and $9.6 million during the years ended December 31, 2014, 2013 and 2012, respectively. The Company realized no income tax benefit for the year ended December 31, 2014, and $1.4 million, and $4.6 million of income tax benefits for the years ended December 31, 2013 and 2012, respectively, which increased its Additional Paid-in-Capital (APIC) pool by $6.5 million as of December 31, 2014. As of December 31, 2014, $2.0 million of unrecognized compensation cost related to stock options granted under the LTSIP is expected to be recognized over a weighted-average period of 1.87 years. During the year ended December 31, 2014, QEP issued shares for stock option exercises from its treasury stock and received $1.5 million in cash in relation to the exercise of stock options.

Restricted Shares
Restricted share grants typically vest in equal installments over a three-year period from the grant date. The grant date fair value is determined based on the closing bid price of the Company's common stock on the grant date. The total fair value of restricted stock that vested during the years ended December 31, 2014, 2013 and 2012, was $26.8 million, $19.8 million and $16.7 million, respectively. The Company realized an income tax expense of $0.5 million, $0.1 million and $0.3 million for the years ended December 31, 2014, 2013 and 2012, respectively. Restricted stock increased the Company's APIC pool by $0.3 million as of December 31, 2014. The weighted average grant-date fair value of restricted stock granted during the years was $31.40 per share, $30.06 per share and $30.54 per share for the years ended December 31, 2014, 2013 and 2012, respectively. As of December 31, 2014, $18.3 million of unrecognized compensation cost related to restricted shares granted under the LTSIP is expected to be recognized over a weighted-average vesting period of 2.10 years.

Transactions involving restricted shares under the terms of the LTSIP are summarized below:

	Restricted Shares Outstanding	Weighted-Average Grant-Date Fair Value
		(per share)
Unvested balance at December 31, 2013	1,388,953	$ 30.96
Granted	**1,033,023**	**31.40**
Vested	**(855,720)**	**31.39**
Forfeited	**(139,803)**	**31.00**
Unvested balance at December 31, 2014	**1,426,453**	**$ 31.02**

Performance Share Units
The performance share units' cash payouts are dependent upon the Company's total shareholder return compared to a group of its peers over a three-year period. The awards are denominated in share units but delivered in cash at the end of the performance period. The weighted average grant-date fair values of the performance share units granted during the years ended December 31, 2014, 2013 and 2012, were $31.57, $30.12, and $30.75 per unit, respectively. As of December 31, 2014, $2.3 million of unrecognized compensation cost classified as a liability, or the fair market value, related to performance shares granted under the CIP is expected to be recognized over a weighted-average vesting period of 1.90 years.

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

	Performance Share Units Outstanding	Weighted-Average Grant-Date Fair Value
Unvested balance at December 31, 2013	480,660	$ 32.33
Granted	**256,101**	**31.57**
Vested	**(73,956)**	**37.17**
Canceled	**(83,545)**	**35.84**
Forfeited	**(27,051)**	**30.60**
Unvested balance at December 31, 2014	**552,209**	**$ 30.85**

Note 12 - Employee Benefits

Defined Benefit Pension Plans and Other Postretirement Benefits
The Company maintains the QEP Resources, Inc. Retirement Plan, a closed, defined-benefit pension plan providing coverage to 62 active and suspended participants, or 8%, of QEP's active employees and to 152 participants that are retired or terminated and vested (the Pension Plan). QEP also sponsors an unfunded Supplemental Executive Retirement Plan. Pension-plan benefits are based on the employee's age at retirement, years of service and highest earnings in a consecutive 72 semi-monthly pay period during the 10 years preceding retirement. QEP pension plans include a qualified and a nonqualified retirement plan. Postretirement health care benefits and life insurance are provided only to employees hired before January 1, 1997. Of the 62 active, pension eligible employees, 39 are also eligible for the postretirement medical and life insurance plans when they retire. As of December 31, 2014, 36 retirees are enrolled in this plan. The Company has capped its exposure to increasing medical costs by paying a fixed dollar monthly contribution toward these retiree benefits. The Company's contribution is prorated based on an employee's years of service at retirement; only those employees with 25 or more years of service receive the maximum company contribution. At December 31, 2014 and 2013, QEP's accumulated benefit obligation exceeded the fair value of its qualified retirement plan assets. At December 31, 2014 and 2013, QEP's nonqualified retirement plan was unfunded.

During the year ended December 31, 2014, the Company recognized a $9.3 million loss on curtailment and $1.9 million in expenses for special termination benefits in connection with the Midstream Sale (see Note 3 - Discontinued Operations) and the 2014 property sales in the Midcontinent area (see Note 2 - Acquisitions and Divestitures). The Pension Plan was amended to provide certain termination benefits for participants impacted by the Midstream Sale and the 2014 Midcontinent property sales who were aged 50-54 as of the date of their separation from the Company. These expenses are included within "Net income from discontinued operations, net of income tax" and "Net gain (loss) from asset sales" for the year ended December 31, 2014, on the Consolidated Statements of Operations. During the year ended December 31, 2012, the Company recognized a $2.2 million loss on curtailment as part of its restructuring and related termination benefits (see Note 8 - Restructuring Costs). A curtailment is recognized immediately when there is a significant reduction in, or an elimination of, defined benefit accruals for present employees' future services. During the year ended December 31, 2014, the Company made contributions of $8.1 million to its funded qualified pension plan. Contributions to funded qualified plans increase plan assets. During the year ended December 31, 2014, the Company made payments of $4.9 million of benefits pursuant to its unfunded nonqualified retirement plan. Payments to the unfunded nonqualified plans are used to fund current benefit payments. During 2015, the Company expects to contribute approximately $4.0 million to its funded pension plan, pay approximately $4.4 million of benefits under its unfunded nonqualified pension plan and pay approximately $0.3 million for retiree health care and life insurance benefits. The accumulated benefit obligation for all defined-benefit pension plans was $121.8 million and $101.0 million at December 31, 2014 and 2013, respectively.

The following table sets forth changes in the benefit obligations and fair value of plan assets for the Company's pension and other postretirement benefit plans for the years ended December 31, 2014 and 2013, as well as the funded status of the plans and amounts recognized in the financial statements at December 31, 2014 and 2013:

	Pension benefits		Other postretirement benefits	
	2014	2013	**2014**	2013
	(in millions)			
Change in benefit obligation				
Benefit obligation at January 1,	**$ 118.0**	$ 129.7	**$ 5.9**	$ 6.7
Service cost	**2.6**	3.3	**—**	0.1
Interest cost	**5.3**	4.8	**0.3**	0.3
Special termination benefits	**1.9**	—	**—**	—
Curtailments	**(8.2)**	—	**(0.2)**	—
Plan settlements	**(2.3)**	—	**—**	—
Benefit payments	**(5.5)**	(5.5)	**—**	(0.1)
Actuarial loss (gain)	**20.8**	(14.3)	**0.6**	(1.1)
Benefit obligation at December 31,	**$ 132.6**	$ 118.0	**$ 6.6**	$ 5.9
Change in plan assets				
Fair value of plan assets at January 1,	**$ 71.7**	$ 55.3	**$ —**	$ —
Actual gain on plan assets	**4.5**	10.4	**—**	—
Company contributions to the plan	**13.0**	11.5	**—**	0.1
Benefit payments	**(5.5)**	(5.5)	**—**	(0.1)
Plan settlements	**(2.3)**	—	**—**	—
Fair value of plan assets at December 31,	**81.4**	71.7	**—**	—
Underfunded status (current and long-term)	**$ (51.2)**	$ (46.3)	**$ (6.6)**	$ (5.9)
Amounts recognized in balance sheets				
Accounts payable and accrued expenses	**$ (4.3)**	$ (5.5)	**$ (0.3)**	$ (0.2)
Other long-term liabilities	**(46.9)**	(40.8)	**(6.3)**	(5.7)
Total amount recognized in balance sheet	**$ (51.2)**	$ (46.3)	**$ (6.6)**	$ (5.9)
Amounts recognized in AOCI				
Net actuarial loss	**$ 21.2**	$ 9.5	**$ 0.6**	$ 0.2
Prior service cost	**16.1**	30.1	**1.4**	3.0
Total amount recognized in AOCI	**$ 37.3**	$ 39.6	**$ 2.0**	$ 3.2

The following table sets forth the Company's pension and other postretirement benefit cost and amounts recognized in other comprehensive income (before tax) for the respective years ended December 31:

	Pension benefits			Other postretirement benefits		
	2014	2013	2012	**2014**	2013	2012
Components of net periodic benefit cost						
Service cost	**$ 2.6**	$ 3.3	$ 4.0	**$ —**	$ 0.1	$ 0.1
Interest cost	**5.3**	4.8	5.1	**0.3**	0.3	0.3
Expected return on plan assets	**(5.1)**	(3.9)	(3.6)	**—**	—	—
Curtailment loss	**9.3**	—	2.2	**1.4**	—	—
Special termination benefits	**1.9**	—	—	**—**	—	—
Settlements	**0.7**	—	—	**—**	—	—
Amortization of prior service costs	**4.7**	5.0	5.3	**0.3**	0.3	0.3
Amortization of actuarial loss	**0.8**	2.3	1.9	**—**	0.1	0.1
Periodic expense	**$ 20.2**	$ 11.5	$ 14.9	**$ 2.0**	$ 0.8	$ 0.8
Components recognized in accumulated other comprehensive income						
Current period actuarial loss (gain)	**$ 21.5**	$ (20.8)	$ 15.9	**$ 0.6**	$ (1.0)	$ 0.4
Amortization of actuarial loss	**(0.8)**	(2.3)	(1.9)	**—**	(0.1)	(0.1)
Amortization of prior service cost	**(14.0)**	(5.0)	(5.3)	**(1.7)**	(0.4)	(0.4)
Loss on curtailment in current period	**(8.2)**	—	(2.2)	**(0.2)**	—	—
Settlements	**(0.7)**	—	—	**—**	—	—
Total amount recognized in accumulated other comprehensive income	**$ (2.2)**	$ (28.1)	$ 6.5	**$ (1.3)**	$ (1.5)	$ (0.1)

The estimated portion of net actuarial loss and net prior service cost for the pension plans that will be amortized from AOCI into net periodic benefit cost in 2015 is $4.1 million, which represents amortization of prior service cost recognition and actuarial losses. The estimated portion to be recognized in net periodic cost for other postretirement benefits from AOCI in 2015 is $0.2 million, which represents amortization of prior service cost recognition. Amortization of prior service costs and actuarial losses/gains out of AOCI are recognized in the Consolidated Statements of Operations in "General and administrative."

Following are the weighted-average assumptions (weighted by the plan level benefit obligation for pension benefits) used by the Company to calculate pension and other postretirement benefit obligations at December 31, 2014 and 2013:

	Pension benefits		Other postretirement benefits	
	2014	2013	**2014**	2013
Discount rate	**3.94%**	4.75%	**4.00%**	5.00%
Rate of increase in compensation	**4.00%**	4.00%	**4.00%**	4.00%

The discount rate assumptions used by the Company represents an estimate of the interest rate at which the pension and other postretirement obligations could effectively be settled on the measurement date.

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

	Pension benefits			Other postretirement benefits		
	2014	2013	2012	**2014**	2013	2012
Discount rate	**4.40%**	3.69%	4.38%	**5.00%**	4.10%	4.70%
Expected long-term return on plan assets	**7.00%**	6.75%	7.25%	**n/a**	n/a	n/a
Rate of increase in compensation	**4.00%**	3.60%	3.60%	**4.00%**	3.60%	4.00%

In selecting the assumption for expected long-term rate of return on assets, the Company considers the average rate of return expected on the funds to be invested to provide benefits. This includes considering the plan's asset allocation, historical returns on these types of assets, the current economic environment and the expected returns likely to be earned over the life of the plan. No plan assets are expected to be returned to the Company in 2015. Historical health care cost trend rates are not applicable to the Company, because the Company's medical costs are capped at a fixed amount. As the Company's medical costs are capped at a fixed amount, the sensitivity to increases and decreases in the health-care inflation rate is not applicable.

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

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

Debt securities: Investment grade intermediate-term debt assets are invested in funds holding a diversified portfolio of debt of governments, corporations and mortgage borrowers with average maturities of 5 to 10 years and investment grade credit ratings. Investment grade long-term debt assets are invested in a diversified portfolio of debt of corporate and non-corporate issuers, with an average maturity of more than ten years and investment grade credit ratings. High yield and bank loan assets are held in funds holding a diversified portfolio of these instruments with an average maturity of 5 to 7 years.

Although the actual allocation to cash and short-term investments is minimal (less than 1%), larger cash allocations may be held from time to time if deemed necessary for operational aspects of the retirement plan. Cash is invested in a high-quality, short-term temporary investment fund that purchases investment-grade quality short-term debt issued by governments and corporations.

Commingled funds: The EBC made the decision to invest all of the retirement plan assets in commingled funds as these funds typically have lower expense ratios and are more tax efficient than mutual funds. While commingled funds are classified as Level 3 assets because there are calculations involved in determining the net asset value of the funds, the underlying assets can be traced back to observable asset values and these commingled funds are audited annually by an independent accounting firm.

The fair value measurement provision of ASC 820, *Fair Value Measurements*, defines fair value in applying generally accepted accounting principles as well as establishes a framework for measuring fair value and for making disclosures about fair-value measurements. Fair value measurement establishes a fair-value hierarchy. Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that are accessible at the measurement date. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for an asset, either directly or indirectly. Level 3 inputs are unobservable and significant to the fair value measurement. The Company's Level 3 investments are public investment vehicles valued using the net asset value (NAV) of the fund, but are considered Level 3 because they are commingled funds. The NAV is based on the value of the underlying assets owned by the fund excluding transaction costs, and minus liabilities.

The following table sets forth by level, within the fair value hierarchy, the fair value of pension and postretirement benefit assets:

	December 31, 2014				
	Level 1	Level 2	Level 3	Total	Percentage of total
	(in millions except percentages)				
Cash and short-term investments	**$ —**	**$ —**	**$ 0.3**	**$ 0.3**	**—%**
Equity securities:					
Domestic	**—**	**—**	**36.7**	**36.7**	**45%**
International	**—**	**—**	**20.2**	**20.2**	**25%**
Fixed income	**—**	**—**	**24.2**	**24.2**	**30%**
Total investments	**—**	**—**	**$ 81.4**	**$ 81.4**	**100%**

	December 31, 2013				
	Level 1	Level 2	Level 3	Total	Percentage of total
	(in millions except percentages)				
Cash and short-term investments	$ —	$ —	$ 0.3	$ 0.3	—%
Equity securities:					
Domestic	—	—	29.3	29.3	41%
International	—	—	21.3	21.3	30%
Fixed income	—	—	20.8	20.8	29%
Total investments	—	—	$ 71.7	$ 71.7	100%

The following table presents a summary of changes in the fair value of QEP's Level 3 investments:

	Year ended December 31,	
	2014	2013
	(in millions)	
Balance at January 1,	**$ 71.7**	55.2
Employer contributions	**8.1**	8.1
Unrealized gains (losses)	**(1.0)**	9.8
Realized gains	**5.9**	1.0
Administrative fees	**(0.4)**	(0.3)
Benefits paid	**(2.9)**	(2.1)
Balance at December 31,	**$ 81.4**	$ 71.7

Expected Benefit Payments
As of December 31, 2014, the following future benefit payments are expected to be paid:

	Pension	Postretirement benefits
	(in millions)	
2015	$ 8.3	$ 0.3
2016	7.0	0.4
2017	6.3	0.4
2018	6.3	0.4
2019	7.2	0.4
2020 through 2024	41.8	1.8

Employee Investment Plan
QEP employees may participate in the QEP Employee Investment Plan, a defined-contribution plan (the 401(k) Plan). The 401(k) Plan allows eligible employees to make investments, including purchasing shares of QEP common stock, through payroll deduction at the current fair market value on the transaction date. For the years ended December 31, 2014 and 2013, the

Company made matching contributions for employees not covered by the Pension Plan equal to 100% of employees' contributions up to a maximum of 8% of their qualifying earnings. Employees in the Pension Plan are eligible for a 6% match. For the year ended December 31, 2012, the Company made matching contributions equal to 100% of employees' contributions up to a maximum of 6% of their qualifying earnings. The Company may contribute a discretionary portion beyond the Company's matching contribution to employees not in the Pension Plan, and for the year ended December 31, 2012, the Company made such discretionary contributions equal to 2% of each eligible employee's compensation. The Company recognizes expense equal to its yearly contributions, which amounted to $7.6 million, $6.9 million and $6.4 million during the years ended December 31, 2014, 2013 and 2012, respectively.

Note 13 - Income Taxes

Details of income tax provisions and deferred income taxes from continuing operations are provided in the following tables. The components of income tax provisions and benefits were as follows:

	Year Ended December 31,		
	2014	2013	2012
		(in millions)	
Federal income tax provision (benefit)			
Current	**$ (324.0)**	$ (92.2)	$ (10.3)
Deferred	**110.3**	152.3	15.6
State income tax provision (benefit)			
Current	**(15.5)**	(1.4)	(1.8)
Deferred	**(3.3)**	1.4	(5.4)
Total income tax provision (benefit)	**$ (232.5)**	$ 60.1	$ (1.9)

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

	Year Ended December 31,		
	2014	2013	2012
Federal income taxes statutory rate	**35.0 %**	35.0 %	35.0 %
Increase (decrease) in rate as a result of:			
State income taxes, net of federal income tax benefit	**(1.5)%**	(5.0)%	(2,220.0)%
State rate change	**3.4 %**	— %	— %
Penalties	**— %**	0.4 %	80.0 %
Return to provision adjustment	**(0.4)%**	5.0 %	1,400.0 %
Book impairment of goodwill	**— %**	18.6 %	— %
Other	**(0.3)%**	(0.4)%	325.0 %
Effective income tax rate	**36.2 %**	53.6 %	(380.0)%

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

	December 31,	
	2014	2013
	(in millions)	
Deferred tax liabilities		
Property, plant and equipment	**$ 1,402.9**	$ 1,455.6
Commodity price and interest rate derivatives	**127.7**	—
Total deferred tax liabilities	**1,530.6**	1,455.6
Deferred tax assets		
Commodity price and interest rate derivatives	**—**	9.8
Net operating loss and tax credit carryforwards	**11.7**	54.4
Employee benefits and compensation costs	**43.0**	36.1
Accrued litigation loss contingency	**—**	0.8
Bonus and vacation accrual	**16.3**	9.0
Other	**12.4**	8.5
Total deferred tax assets	**83.4**	118.6
Net deferred income tax liability	**$ 1,447.2**	$ 1,337.0
Balance sheet classification		
Deferred income tax asset - current	**$ —**	$ 27.9
Deferred income tax liability - current	**84.5**	—
Deferred income tax liability - non-current	**1,362.7**	1,364.9
Net deferred income tax liability	**$ 1,447.2**	$ 1,337.0

The amounts and expiration dates of net operating loss and tax credit carryforwards at December 31, 2014 are as follows:

	Expiration Dates	Amounts
		(in millions)
State net operating loss and tax credit carryforwards	2015-2033	**$ 30.1**
State net operating loss valuation allowance		**(18.4)**
U.S. alternative minimum tax credit	Indefinite	**—**
Total		**$ 11.7**

The valuation allowance of $18.4 million was established in 2014 against the available state net operating loss and is related primarily to losses incurred in Oklahoma. Due to the 2014 Midcontinent property sales in which the Company sold its interests in most of its properties in Oklahoma, the Company does not forecast sufficient taxable income to utilize the net operating loss in Oklahoma.

Note 14 - Operations by Line of Business

QEP's lines of business include oil and gas exploration and production (QEP Energy); and marketing, the Haynesville Gathering System, an underground storage reservoir, and corporate (QEP Marketing and Other). The lines of business are managed separately and therefore the financial information is presented separately due to the distinct differences in the nature of operations of each line of business, among other factors.

Our financial results for 2014 and for prior periods have been revised, in accordance with GAAP, to reflect the impact of the Midstream Sale. See Note 3 - Discontinued Operations for detailed information on the Midstream Sale.

The following table is a summary of operating results for the year ended December 31, 2014, by line of business:

	QEP Energy	QEP Marketing and Other	Eliminations	Discontinued Operations	QEP Consolidated
			(in millions)		
REVENUES					
From unaffiliated customers	$ 2,524.6	$ 889.7	$ —	$ —	$ 3,414.3
From affiliated customers	—	1,492.6	(1,492.6)	—	—
Total Revenues	2,524.6	2,382.3	(1,492.6)	—	3,414.3
OPERATING EXPENSES					
Purchased gas, oil and NGL expense	150.0	2,356.6	(1,475.4)	—	1,031.2
Lease operating expense	240.1	—	—	—	240.1
Gas, oil and NGL transportation and other handling costs	291.5	—	(13.9)	—	277.6
Gathering and other expense	—	6.8	(0.1)	—	6.7
General and administrative	201.3	6.3	(3.2)	—	204.4
Production and property taxes	204.0	1.2	—	—	205.2
Depreciation, depletion and amortization	984.4	10.3	—	—	994.7
Impairment and exploration expenses	1,153.1	—	—	—	1,153.1
Total Operating Expenses	3,224.4	2,381.2	(1,492.6)	—	4,113.0
Net gain (loss) from asset sales	(148.6)	—	—	—	(148.6)
OPERATING INCOME (LOSS)	(848.4)	1.1	—	—	(847.3)
Realized and unrealized gains (losses) on derivative contracts	367.2	(3.9)	—	—	363.3
Interest and other income	11.8	209.7	(208.7)	—	12.8
Income from unconsolidated affiliates	0.3	—	—	—	0.3
Loss from early extinguishment of debt	—	(2.0)	—	—	(2.0)
Interest expense	(210.3)	(167.5)	208.7	—	(169.1)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	(679.4)	37.4	—	—	(642.0)
Income tax (provision) benefit	246.9	(14.4)	—	—	232.5
NET INCOME (LOSS) FROM CONTINUING OPERATIONS	(432.5)	23.0	—	—	(409.5)
Net income from discontinued operations, net of income tax	—	—	—	1,193.9	1,193.9
NET INCOME (LOSS) ATTRIBUTABLE TO QEP	$ (432.5)	$ 23.0	$ —	$ 1,193.9	$ 784.4
Identifiable total assets	$ 8,001.1	$ 1,285.7	$ —	$ —	$ 9,286.8
Cash capital expenditures	2,660.3	10.9	—	55.2	$ 2,726.4
Accrued capital expenditures	2,670.5	13.6	—	50.7	$ 2,734.8

The following table is a summary of operating results for the year ended December 31, 2013, by line of business:

	QEP Energy	QEP Marketing and Other	Eliminations	Discontinued Operations	QEP Consolidated
			(in millions)		
REVENUES					
From unaffiliated customers	$ 2,092.8	$ 592.3	$ —	$ —	$ 2,685.1
From affiliated customers	—	1,008.9	(1,008.9)	—	—
Total Revenues	2,092.8	1,601.2	(1,008.9)	—	2,685.1
OPERATING EXPENSES					
Purchased gas, oil and NGL expense	197.1	1,570.5	(984.1)	—	783.5
Lease operating expense	181.3	—	—	—	181.3
Gas, oil and NGL transportation and other handling costs	242.2	—	(20.2)	—	222.0
Gathering and other expense	—	8.4	—	—	8.4
General and administrative	160.6	4.4	(4.6)	—	160.4
Production and property taxes	159.8	1.5	—	—	161.3
Depreciation, depletion and amortization	954.2	9.6	—	—	963.8
Impairment and exploration expenses	104.9	—	—	—	104.9
Total Operating Expenses	2,000.1	1,594.4	(1,008.9)	—	2,585.6
Net gain (loss) from asset sales	104.1	(0.6)	—	—	103.5
OPERATING INCOME (LOSS)	196.8	6.2	—	—	203.0
Realized and unrealized gains (losses) on derivative contracts	59.1	(0.2)	—	—	58.9
Interest and other income	3.6	206.9	(195.3)	—	15.2
Income from unconsolidated affiliates	0.2	—	—	—	0.2
Interest expense	(192.6)	(167.8)	195.3	—	(165.1)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	67.1	45.1	—	—	112.2
Income tax provision	(41.5)	(18.6)	—	—	(60.1)
NET INCOME (LOSS) FROM CONTINUING OPERATIONS	25.6	26.5	—	—	52.1
Net income from discontinued operations, net of income tax	—	—	—	107.3	107.3
NET INCOME (LOSS ATTRIBUTABLE TO QEP	$ 25.6	$ 26.5	$ —	$ 107.3	$ 159.4
Identifiable total assets	$ 7,937.0	$ 182.2	$ —	$ 1,289.7	$ 9,408.9
Cash capital expenditures	1,488.6	25.1	—	88.9	$ 1,602.6
Accrued capital expenditures	1,467.2	24.6	—	85.6	$ 1,577.4

The following table is a summary of operating results for the year ended December 31, 2012, by line of business:

	QEP Energy	QEP Marketing and Other	Eliminations	Discontinued Operations	QEP Consolidated
			(in millions)		
REVENUES					
From unaffiliated customers	$ 1,615.4	$ 456.3	$ —	$ —	$ 2,071.7
From affiliated customers	—	611.2	(611.2)	—	—
Total Revenues	1,615.4	1,067.5	(611.2)	—	2,071.7
OPERATING EXPENSES					
Purchased gas, oil and NGL expense	224.7	1,021.1	(575.1)	—	670.7
Lease operating expense	175.8	—	—	—	175.8
Gas, oil and NGL transportation and other handling costs	228.1	—	(30.0)	—	198.1
Gathering and other expense	—	8.2	—	—	8.2
General and administrative	252.8	1.7	(6.1)	—	248.4
Production and property taxes	97.2	1.3	—	—	98.5
Depreciation, depletion and amortization	838.4	11.8		—	850.2
Impairment and exploration expenses	144.2	—	—	—	144.2
Total Operating Expenses	1,961.2	1,044.1	(611.2)	—	2,394.1
Net gain from asset sales	1.2	—	—	—	1.2
OPERATING INCOME (LOSS)	(344.6)	23.4	—	—	(321.2)
Realized and unrealized gains (losses) on derivative contracts	434.9	(1.4)	—	—	433.5
Interest and other income	6.2	132.3	(123.5)	—	15.0
Income from unconsolidated affiliates	0.1	—	—	—	0.1
Loss on extinguishment of debt	—	(0.6)	—	—	(0.6)
Interest expense	(116.8)	(133.0)	123.5	—	(126.3)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	(20.2)	20.7	—	—	0.5
Net Income tax benefit (provision)	12.1	(10.2)	—	—	1.9
NET INCOME (LOSS) FROM CONTINUING OPERATIONS	(8.1)	10.5	—	—	2.4
Net income from discontinued operations, net of income tax	—	—	—	125.9	125.9
NET INCOME (LOSS) ATTRIBUTABLE TO QEP	$ (8.1)	$ 10.5	$ —	$ 125.9	$ 128.3
Identifiable assets	$ 7,436.5	$ 244.6	$ —	$ 1,427.4	$ 9,108.5
Cash capital expenditures	2,621.1	22.4	—	156.2	2,799.7
Accrued capital expenditures	2,702.4	21.6	—	164.2	2,888.2
Goodwill	59.5	—	—	—	59.5

Note 15 - Quarterly Financial Information (unaudited)

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

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
	(in millions, except per share information)				
2014					
Revenues	**$ 817.5**	**$ 887.2**	**$ 910.0**	**$ 799.6**	**$ 3,414.3**
Operating income (loss)	**140.8**	**(35.9)**	**115.1**	**(1,067.3)**	**(847.3)**
Income (loss) from continuing operations	**12.7**	**(106.1)**	**153.7**	**(469.8)**	**(409.5)**
Discontinued operations, net of income taxes [1]	**27.0**	**13.8**	**17.4**	**1,135.7**	**1,193.9**
Net income (loss) attributable to QEP	**39.7**	**(92.3)**	**171.1**	**665.9**	**784.4**
Non-recurring items in operating income (loss) [2]	**0.4**	**(202.5)**	**(11.9)**	**(1,077.8)**	**(1,291.8)**
Per share information attributable to QEP					
Basic EPS from continuing operations	**$ 0.07**	**$ (0.59)**	**$ 0.85**	**$ (2.62)**	**$ (2.28)**
Basic EPS from discontinued operations	**0.15**	**0.08**	**0.10**	**6.34**	**6.64**
Diluted EPS from continuing operations	**0.07**	**(0.59)**	**0.84**	**(2.62)**	**(2.28)**
Diluted EPS from discontinued operations	**0.15**	**0.08**	**0.10**	**6.34**	**6.64**
2013					
Revenues	$ 651.3	$ 694.0	$ 719.5	$ 620.3	2,685.1
Operating income (loss)	27.3	159.1	83.3	(66.7)	203.0
Income (loss) from continuing operations	(24.8)	149.2	12.1	(84.4)	52.1
Discontinued operations, net of income taxes [1]	20.5	29.2	25.2	32.4	107.3
Net income (loss) attributable to QEP	(4.3)	178.4	37.3	(52.0)	$ 159.4
Non-recurring items in operating income (loss) [2]	(0.2)	100.2	9.0	$ (98.5)	10.5
Per share information attributable to QEP					
Basic EPS from continuing operations	$ (0.14)	$ 0.83	$ 0.07	$ (0.47)	$ 0.29
Basic EPS from discontinued operations	0.12	0.16	0.14	0.18	0.60
Diluted EPS from continuing operations	(0.14)	0.83	0.07	(0.47)	0.29
Diluted EPS from discontinued operations	0.12	0.16	0.14	0.18	0.60

[1] 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.
[2] Includes net gains and losses from asset sales and losses due to asset impairments.

Note 16 - Supplemental Oil and Gas Information (Unaudited)

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

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

	December 31,	
	2014	2013
	(in millions)	
Proved properties	**$ 12,278.7**	$ 11,571.4
Unproved properties, net	**825.2**	665.1
Total proved and unproved properties	**13,103.9**	12,236.5
Accumulated depreciation, depletion and amortization	**(6,153.0)**	(4,930.9)
Net capitalized costs	**$ 6,950.9**	$ 7,305.6

Costs Incurred

The costs incurred in oil and gas acquisition, exploration and development activities are displayed in the table below. Development costs are net of the change in accrued capital costs of $10.2 million and ARO additions and revisions of $51.1 million during the year ended December 31, 2014. The costs incurred to advance the development of reserves that were classified as proved undeveloped were approximately $796.7 million in 2014, $645.9 million in 2013, and $513.0 million in 2012.

	Year Ended December 31,		
	2014	2013	2012
	(in millions)		
Property acquisitions			
Unproved	**$ 496.3**	$ 9.3	$ 692.6
Proved	**465.4**	31.6	714.4
Total property acquisitions	**961.7**	40.9	1,407.0
Exploration (capitalized and expensed)	**23.6**	14.6	14.3
Development	**1,695.1**	1,440.8	1,310.0
Total costs incurred	**$ 2,680.4**	$ 1,496.3	$ 2,731.3

Results of Operations

Following are the results of operations of QEP Energy's oil and gas producing activities, before allocated corporate overhead and interest expenses.

	Year Ended December 31,		
	2014	2013	2012
	(in millions)		
Revenues	**$ 2,374.6**	$ 1,901.2	$ 1,393.4
Production costs	**735.6**	583.3	501.1
Exploration expenses	**9.9**	11.9	11.2
Depreciation, depletion and amortization	**984.4**	954.2	838.4
Impairment	**1,143.2**	93.0	133.0
Total expenses	**2,873.1**	1,642.4	1,483.7
Income (loss) before income taxes	**(498.5)**	258.8	(90.3)
Income tax benefit (expense)	**182.5**	(96.3)	33.6
Results of operations from producing activities excluding allocated corporate overhead and interest expenses	**$ (316.0)**	$ 162.5	$ (56.7)

Estimated Quantities of Proved Oil and Gas Reserves

Estimates of proved oil and gas reserves have been completed in accordance with professional engineering standards and the Company's established internal controls, which includes the compliance oversight of a multi-functional reserves review committee responsible to the Company's Board of Directors. QEP Energy's estimated proved reserves have been prepared by Ryder Scott Company, L.P. and DeGolyer and MacNaughton, independent reservoir engineering consultants, in accordance with the SEC's Regulation S-X and ASC 932 as amended. The individuals performing reserves estimates possess professional qualifications and demonstrate competency in reserves estimation and evaluation. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

All of QEP Energy's proved undeveloped reserves at December 31, 2014, are scheduled to be developed within five years from the date such locations were initially disclosed as proved undeveloped reserves; however, long-term development of gas reserves in Pinedale is governed by the Bureau of Land Management's September 2008, Record of Decision (ROD) on the Final Supplemental Environmental Impact Statements. 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.

As of December 31, 2014, all of the Company's oil and gas reserves are attributable to properties within the United Sates. A summary of the Company's change in quantities of proved oil and gas reserves for the years ended December 31, 2012, 2013 and 2014 are as follows:

	Gas	Oil	NGL	Total
	(Bcf)	(MMbbl)	(MMbbl)	(Bcfe)
Balance at December 31, 2011	2,749.4	67.5	76.6	3,613.8
Revisions of previous estimates(1)	(240.6)	(1.5)	0.7	(244.8)
Extensions and discoveries(2)	330.6	17.3	23.0	572.5
Purchase of reserves in place(3)	32.3	42.0	4.9	313.8
Sale of reserves in place	—	—	—	—
Production	(249.3)	(6.3)	(5.3)	(319.2)
Balance at December 31, 2012	2,622.4	119.0	99.9	3,936.1
Revisions of previous estimates(4)	(288.3)	1.3	(8.0)	(328.5)
Extensions and discoveries(5)	455.6	38.3	16.4	783.8
Purchase of reserves in place	1.0	1.9	0.2	13.4
Sale of reserves in place	(16.9)	(1.7)	(1.1)	(33.9)
Production	(218.9)	(10.2)	(4.8)	(309.0)
Balance at December 31, 2013	2,554.9	148.6	102.6	4,061.9
Revisions of previous estimates(6)	**27.1**	**(4.0)**	**1.4**	**11.3**
Extensions and discoveries(7)	**141.4**	**16.8**	**8.6**	**294.1**
Purchase of reserves in place(8)	**72.5**	**35.7**	**12.3**	**360.7**
Sale of reserves in place(9)	**(299.4)**	**(7.5)**	**(21.5)**	**(473.4)**
Production	**(179.3)**	**(17.1)**	**(6.8)**	**(322.7)**
Balance at December 31, 2014	**2,317.2**	**172.5**	**96.6**	**3,931.9**
Proved developed reserves				
Balance at December 31, 2011	1,538.3	33.0	38.4	1,966.3
Balance at December 31, 2012	1,531.7	47.4	49.3	2,111.9
Balance at December 31, 2013	1,406.3	71.8	52.8	2,154.0
Balance at December 31, 2014	**1,288.4**	**99.3**	**52.2**	**2,197.5**
Proved undeveloped reserves				
Balance at December 31, 2011	1,211.1	34.6	38.2	1,647.5
Balance at December 31, 2012	1,090.7	71.6	50.6	1,824.2
Balance at December 31, 2013	1,148.6	76.8	49.8	1,907.9
Balance at December 31, 2014	**1,028.8**	**73.2**	**44.4**	**1,734.4**

(1) Revisions of previous estimates in 2012 include negative impacts due to 152.4 Bcfe pricing revisions, 35.6 Bcfe performance revisions, 27.6 Bcfe operating cost revisions and 29.1 Bcfe other revisions. The 152.4 Bcfe pricing revisions were due to lower gas prices which reduced gas reserve volumes by 147.7 Bcf. Negative performance revisions were driven by a 56.0 Bcfe decrease in Pinedale reserves. Pinedale reserve adjustments are based on additional production history, well performance and current pricing causing a revised future development plan which includes lower density drilling in some flank areas, resulting in 25 proved undeveloped (PUD) locations being eliminated. Reserve decreases are partially offset by a 35.9 Bcfe positive impact from revisions in the Uinta Basin, due to the installation of the Iron Horse Cryogenic plant to increase liquid recoveries and improved well performance in the Red Wash Mesaverde field.

(2) Extensions and discoveries in 2012 increased proved reserves by 572.5 Bcfe, primarily related to extensions and discoveries in the Uinta Basin of 258.3 Bcfe, in Pinedale of 151.6 Bcfe, and 162.6 Bcfe in the Williston Basin, Midcontinent and Other Northern areas of operation combined. All of these extensions and discoveries related to new well completions and the associated new PUD locations as part of the Company's development drilling plans.

(3) Purchase of reserves in place in 2012 primarily relate to the Company's $1.4 billion Williston Basin Acquisition as discussed in Note 2 - Acquisitions and Divestitures.

(4) Revisions of previous estimates in 2013 include positive impacts due to 80.0 Bcfe pricing revisions, negative performance revisions of 265.5 Bcfe, 42.0 Bcfe negative operating cost revisions and 101.0 Bcfe other negative revisions. Pricing revisions were primarily due to increased gas prices which increased reserves by 68.4 Bcfe. Negative performance revisions were driven by a 129.5 Bcfe decrease in Pinedale reserves and 112.7 Bcfe decrease in Haynesville reserves related to reserve adjustments based on additional production history, well performance and current pricing causing a revised future development plan which includes lower density drilling in some areas and a change in well spacing assumptions in these areas.

(5) Extensions and discoveries in 2013 increased proved reserves by 783.8 Bcfe, primarily related to extensions and discoveries in the Williston Basin of 217.6 Bcfe, in Pinedale of 265.3 Bcfe, and 175.9 Bcfe in Haynesville. Extension and discoveries in Pinedale and Haynesville relate to certain less densely spaced wells with higher estimates of recoverable oil and gas, which were booked to replace wells removed from the Company's reserves through negative revisions caused by a change in well spacing assumptions in these areas. Of these extensions and discoveries 687.6 Bcfe related to new PUD locations.

(6) Revisions of previous estimates in 2014 include 248.5 Bcfe negative performance revisions partially offset by positive other revisions of 197.7 Bcfe, operating cost revisions of 39.2 Bcfe and pricing revisions of 22.9 Bcfe. Negative performance revisions were driven by a 194.0 Bcfe decrease in Pinedale reserves related to downward forecast revisions on proved developed (PDP) wells, additional production history on PUD to PDP performance and a downward adjustment in the number of PUD locations. Other negative revisions related to adjustments to shrink and lease operating expense deducts. Pricing revisions were primarily due to increased gas prices, which increased reserves by 21.9 Bcfe.

(7) Extensions and discoveries in 2014 increased proved reserves by 294.1 Bcfe, primarily related to extensions and discoveries in Pinedale of 133.6 Bcfe and the Williston Basin of 123.3 Bcfe. All of these extensions and discoveries related to new well completions and the associated new PUD locations as part of the Company's development drilling plans and new compression well projections in Pinedale.

(8) Purchase of reserves in place in 2014 relate to the Company's Permian Basin Acquisition as discussed in Note 2 - Acquisitions and Divestitures.

(9) Sale of reserves in place primarily related to property sales in the Midcontinent in the second and fourth quarters of 2014 as discussed in Note 2 - Acquisitions and Divestitures.

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

Future net cash flows were calculated at December 31, 2014, 2013 and 2012, by applying prices, which were the simple average of the first-of-the-month commodity prices, adjusted for location and quality differentials, for each of the 12 months during 2014, 2013 and 2012, with consideration of known contractual price changes. The prices used do not include any impact of QEP's commodity derivatives portfolio. The following table provides the average benchmark prices per unit, before location and quality differential adjustments, used to calculate the related reserve category:

	For the year ended December 31,		
	2014	2013	2012
Average benchmark price per unit:			
Gas price (per MMBtu)	**$ 4.35**	$ 3.67	$ 2.76
Oil price (per bbl)	**94.99**	96.94	94.71

Year-end operating expenses, development costs and appropriate statutory income tax rates, with consideration of future tax rates, were used to compute the future net cash flows. All cash flows were discounted at 10% to reflect the time value of cash flows, without regard to the risk of specific properties. The estimated future costs to develop booked proved undeveloped reserves are approximately $925.7 million in 2015, $983.7 million in 2016 and $714.3 million in 2017.

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

- Future commodity prices received for selling the Company's net production will likely differ from those required to be used in these calculations.
- Future operating and capital costs will likely differ from those required to be used in these calculations.

- Future market conditions, government regulations, reservoir conditions and risks inherent in the production of oil and gas may cause production rates in future years to vary significantly from those rates used in the calculations.
- Future revenues may be subject to different production, severance and property taxation rates.
- The selection of a 10% discount rate is arbitrary and may not be a reasonable factor in adjusting for future economic conditions or in considering the risk that is part of realizing future net cash flows from the reserves.

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

	Year Ended December 31,		
	2014	2013	2012
	(in millions)		
Future cash inflows	**$ 28,167.3**	$ 24,805.7	$ 18,200.2
Future production costs	**(9,842.1)**	(8,400.3)	(5,027.2)
Future development costs	**(3,521.3)**	(4,056.7)	(3,927.3)
Future income tax expenses	**(4,304.0)**	(3,284.6)	(2,269.0)
Future net cash flows	**10,499.9**	9,064.1	6,976.7
10% annual discount for estimated timing of net cash flows	**(5,159.9)**	(4,680.2)	(3,942.0)
Standardized measure of discounted future net cash flows	**$ 5,340.0**	$ 4,383.9	$ 3,034.7

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

	Year Ended December 31,		
	2014	2013	2012
	(in millions)		
Balance at January 1,	**$ 4,383.9**	$ 3,034.7	$ 3,525.6
Sales of gas, oil and NGL produced during the period, net of production costs	**(1,639.0)**	(1,317.9)	(892.3)
Net change in sales prices and in production (lifting) costs related to future production	**726.6**	1,236.3	(2,083.5)
Net change due to extensions, discoveries and improved recovery	**979.9**	2,230.7	948.5
Net change due to revisions of quantity estimates	**35.9**	(709.6)	(387.8)
Net change due to purchases of reserves in place	**695.3**	36.8	831.4
Net change due to sales of reserves in place	**(1,153.7)**	(73.2)	—
Previously estimated development costs incurred during the period	**867.5**	722.7	513.0
Changes in estimated future development costs	**409.6**	(596.5)	(209.3)
Accretion of discount	**597.3**	402.2	499.4
Net change in income taxes	**(600.3)**	(601.7)	273.6
Other	**37.0**	19.4	16.1
Net change	**956.1**	1,349.2	(490.9)
Balance at December 31,	**$ 5,340.0**	$ 4,383.9	$ 3,034.7

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

The Company's Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of the design and operation of the Company's disclosure controls and procedures (as such term is defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended), as of December 31, 2014. Based on such evaluation, such officers have concluded that, as of December 31, 2014, the Company's disclosure controls and procedures are designed and effective to ensure that information required to be included in the Company's reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms and that information required to be disclosed in the Company's reports filed or submitted under the Exchange Act is accumulated and communicated to the Company's management including its principal executive officer and principal financial officer, or persons performing similar functions, as appropriate, to allow timely decisions regarding required disclosure.

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

Changes in Internal Controls

There were no changes in the Company's internal controls over financial reporting that occurred during the quarter ended December 31, 2014, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Assessment of Internal Control Over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rule 13a-15(f). The Company's internal control over financial reporting is a process designed under the supervision of QEP's chief executive officer and chief financial officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. Because of its inherent limitations, internal control over financial reporting may not detect or prevent misstatements. Also, projections of any evaluation of the effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or processes may deteriorate.

On May 14, 2013, the Committee of Sponsoring Organizations of the Treadway Commission (COSO) issued an updated version of its *Internal Control - Integrated Framework* (the 2013 Framework). Originally issued in 1992 (the 1992 Framework), the framework helps organizations design, implement and evaluate the effectiveness of internal control concepts and simplify their use and application. As of December 31, 2014, management assessed the effectiveness of our internal control over financial reporting based on the 2013 Framework criteria for effective internal control over financial reporting. Based on the assessment, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2014. Management included in its assessment of internal control over financial reporting all consolidated entities.

PricewaterhouseCoopers, LLP, the independent registered public accounting firm that audited the Consolidated Financial Statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of internal control over financial reporting as of December 31, 2014, which is included in the Consolidated Financial Statements in Item 8 of Part II of this Annual Report on Form 10-K.

ITEM 9B. OTHER INFORMATION

On February 23, 2015, the Company amended the Deferred Compensation Plan for Directors to allow directors to receive amounts previously deferred in shares of Company stock or cash at the time of distribution. Previously, the Plan only allowed such distributions in cash. Additionally, the amendment provides that phantom unit agreements are no longer required for those directors electing to defer compensation. The foregoing description of the Deferred Compensation Plan for Directors is not complete and is qualified in its entirety by reference to the text of the full Deferred Compensation Plan for Directors, which is attached as Exhibit 10.6 hereto and is incorporated herein by reference.

On February 23, 2015, the Company also amended the Deferred Compensation Wrap Plan, which provides officers and key employees with the opportunity to defer the receipt of certain compensation. The amendment allows Company employees to defer compensation attributable to restricted stock and long-term incentive awards if the Company determines to allow such deferrals at the time of granting such awards or thereafter in accordance with certain federal income tax rules. The foregoing description of the Deferred Compensation Wrap Plan is not complete and is qualified in its entirety by reference to the text of the full Deferred Compensation Wrap Plan, which is attached as Exhibit 10.10 hereto and is incorporated herein by reference.

On February 23, 2015, the Company modified the form of award agreement used for grants of performance share units (PSUs) to officers and key employees under the QEP Resources, Inc. Cash Incentive Plan. The PSUs provide compensatory payments to grantees based on the Company’s stock price and total shareholder return over designated performance periods and have historically been paid out in cash following the end of each performance period. Beginning with awards granted in February 2015, the modified agreements will allow the option of settling earned awards in shares of our common stock, with any such shares being delivered under the Company’s LTSIP. The revisions also require grantees to remain employed through the actual date of payment of awards (rather than the end of the performance period) in order to vest in payments, except in the event of an earlier termination on account of the grantee’s death, disability or retirement. The foregoing description of the Performance Share Unit Award Agreement is not complete and is qualified in its entirety by reference to the text of the full Performance Share Unit Award Agreement, which is attached as Exhibit 10.41 hereto and is incorporated herein by reference.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by Item 10 concerning QEP's directors and nominees for directors and other corporate governance matters will be presented in the Company's definitive Proxy Statement prepared for the solicitation of proxies in connection with the Company's Annual Meeting of Stockholders scheduled to be held on May 12, 2015, which the Company expects to file with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2014 (Proxy Statement), and is incorporated by reference herein.

Information about the Company's executive officers can be found in Item 1 of Part I in this Annual Report on Form 10-K.

Information concerning compliance with Section 16(a) of the Exchange Act will be set forth in the Proxy Statement and is incorporated herein by reference.

The Company has a Code of Conduct that applies to all of its directors, officers (including its chief executive officer and chief financial officer) and employees. QEP has posted the Code of Conduct on its website, www.qepres.com. Any waiver of the Code of Conduct for executive officers must be approved by the Company's Board of Directors. QEP will post on its website any amendments to or waivers of the Code of Conduct that apply to executive officers.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 11 will be set forth in the Proxy Statement and is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by Item 12 will be set forth in the Proxy Statement and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by Item 13 will be set forth in the Proxy Statement and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by Item 14 will be set forth in the Proxy Statement and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Financial statements and financial statement schedules filed as part of this report are listed in the index included in Item 8 of Part II Financial Statements and Supplementary Data of this report.

(b) **Exhibits.** The following is a list of exhibits required to be filed as a part of this report in Item 15(b).

Exhibit No.	Description
2.1	Agreement and Plan of Merger dated as of May 18, 2010, between Questar Market Resources, Inc., a Utah corporation, and QEP Resources, Inc., a Delaware corporation. (Incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on May 24, 2010.)
2.2	Separation and Distribution Agreement dated as of June 14, 2010, by and between Questar Corporation and QEP Resources, Inc. (Incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 16, 2010.)
3.1	Certificate of Incorporation dated May 18, 2010. (Incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on May 24, 2010.)
3.2	Amended and Restated Bylaws, deemed effective October 27, 2014. (Incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on October 29, 2014.)
3.3	Certificate of Elimination with respect to Series A Junior Participating Preferred Stock of QEP Resources, Inc. (Incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on May 16, 2012.)
4.1	Indenture dated as of March 1, 2001, between Questar Market Resources, Inc. (predecessor-in-interest to QEP Resources, Inc.) and Bank One, NA, (predecessor-in-interest to Wells Fargo Bank, National Association), as Trustee. (Incorporated by reference to Exhibit 4.01 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on March 13, 2001.)
4.2	The Company's 6.05% Notes due 2016. (Incorporated by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on May 15, 2006.)
4.3	Officers' Certificate setting forth the terms of the Company's 6.05% Notes due 2016. (Incorporated by reference to Exhibit 99.3 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on May 15, 2006.)
4.4	The Company's 6.80% Notes due 2018. (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on April 4, 2008.)
4.5	Officers' Certificate setting forth the terms of the Company's 6.80% Notes due 2018. (Incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on April 4, 2008.)
4.6	The Company's 6.80% Notes due 2020. (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on September 2, 2009.)
4.7	Officers' Certificate setting forth the terms of the Company's 6.80% Notes due 2020. (Incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on September 2, 2009.)
4.8	Officers' Certificate, dated as of August 16, 2010 (including the form of the Company's 6.875% Notes due 2021). (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on August 16, 2010.)
4.9	Indenture, dated as of March 1, 2012, between the Company and Wells Fargo Bank, National Association, as Trustee. (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on March 1, 2012.)
4.10	Officer's Certificate, dated as of March 1, 2012 (including the form of the Company's 5.375% Notes due 2022). (Incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on March 1, 2012.)

4.11	Officer's Certificate, dated as of September 12, 2012 (including form of the Company's 5.250% Notes due 2023). (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on September 14, 2012.)
10.1	Credit Agreement, dated as of August 25, 2011, among QEP Resources, Inc., Wells Fargo Bank, National Association, as the administrative agent, letter of credit issuer and swing line lender, and the lenders party thereto. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on August 29, 2011, as amended by Second Amendment to Credit Agreement, dated as of August 13, 2013, by and among QEP Resources, Inc., the lenders party thereto and Wells Fargo Bank, National Association, in its capacity as administrative agent for the lenders, incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on August 16, 2013, as amended by Third Amendment to Credit Agreement, dated as of January 31, 2014, by and among QEP Resources, Inc., the lenders party thereto and Wells Fargo Bank, National Association, in his capacity as administrative agent for the lenders, incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2014, filed with the Securities and Exchange Commission on May 7, 2014, as amended by Fourth Amendment to Credit Agreement and Commitment Increase Agreement, dated as of December 2, 2014, by and among QEP Resources, Inc., the Lenders party to thereto the Wells Fargo Bank, National Association, in its capacity as administrative agent for the Lenders, incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on December 4, 2014.)
10.2	Term Loan Agreement, dated as of April 18, 2012, among QEP Resources, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on April 20, 2012, as amended by the First Amendment to Term Loan Agreement, dated as of August 13, 2013, by and among QEP Resources, Inc., the lenders party thereto and Wells Fargo Bank, National Association, in its capacity as administrative agent for the lenders, incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on August 16, 2013, as amended by Second Amendment to Term Loan Agreement, dated as of February 25, 2014, by and among QEP Resources, Inc., the lenders party thereto and Wells Fargo Bank, National Association, in its capacity as administrative agent for the lenders, incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2014, filed with the Securities and Exchange Commission on May 7, 2014.)
10.3	Employee Matters Agreement, dated as of June 14, 2010, by and between Questar Corporation and QEP Resources, Inc. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 16, 2010.)
10.4	Tax Matters Agreement, dated as of June 14, 2010, by and between Questar Corporation and QEP Resources, Inc. (Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 16, 2010.)
10.5	Transition Services Agreement, dated as of June 14, 2010, by and between Questar Corporation and QEP Resources, Inc. (Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 16, 2010.)
10.6*+	QEP Resources, Inc. Deferred Compensation Plan for Directors, Amended and Restated, effective as of August 1, 2014 (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2014, filed with the Securities and Exchange Commission on August 6, 2014), as amended and restated by the QEP Resources, Inc. Deferred Compensation Plan for Directors, Amended and Restated, effective as of February 23, 2015.
10.7+	QEP Resources, Inc. Cash Incentive Plan, dated effective as of January 1, 2012. (Incorporated by reference to Appendix A to the Company's Proxy Statement on Schedule 14A filed with the Securities and Exchange Commission on April 3, 2012.)
10.8+	QEP Resources, Inc. 2010 Long-Term Stock Incentive Plan adopted June 12, 2010. (Incorporated by reference to Exhibit 10.9 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 16, 2010.)
10.9+	QEP Resources, Inc. Executive Severance Compensation Plan effective as of March 1, 2012 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on May 16, 2012), as amended and restated by the QEP Resources, Inc. Executive Severance Compensation Plan - CIC effective as of February 23, 2014 (incorporated by reference to Exhibit 10.9 to the Company's Annual Report on Form 10-K for the year ended December 31, 2013, filed with the Securities and Exchange Commission on February 25, 2014.)
10.10*+	QEP Resources, Inc. Amended Deferred Compensation Wrap Plan adopted January 28, 2013. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on January 31, 2013.) As amended and restated by the QEP Resources, Inc. Amended Deferred Compensation Wrap Plan, effective as of February 23, 2015

10.11+	QEP Resources, Inc. Supplemental Executive Retirement Plan adopted June 12, 2010 (Incorporated by reference to Exhibit 10.12 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 16, 2010), as amended by the Amended Deferred Compensation Wrap Plan adopted January 28, 2013. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on January 31, 2013.)
10.12+	QEP Resources, Inc. Form of Nonqualified Stock Option Agreement for nonqualified stock options granted to certain key executives. (Incorporated by reference to Exhibit 10.1. to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
10.13+	QEP Resources, Inc. Form of Nonqualified Stock Option Agreement for nonqualified stock options granted to other officers and key employees. (Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
10.14+	QEP Resources, Inc. Form of Incentive Stock Option Agreement for incentive stock options granted to certain key executives. (Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
10.15+	QEP Resources, Inc. Form of Incentive Stock Option Agreement for incentive stock options granted to other officers and key employees. (Incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
10.16+	QEP Resources, Inc. Form of Restricted Stock Agreement for restricted stock granted to certain key executives. (Incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
10.17+	QEP Resources, Inc. Form of Restricted Stock Agreement for restricted stock granted to other officers and key employees. (Incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
10.18+	QEP Resources, Inc. Form of Restricted Stock Agreement for restricted stock granted to non-employee directors. (Incorporated by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
10.19+	QEP Resources, Inc. Form of Phantom Stock Agreement for phantom stock granted to non-employee directors. (Incorporated by reference to Exhibit 10.8 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
10.20+	QEP Resources, Inc. Form of Restricted Stock Units Agreement for restricted stock units granted to Mr. Keith O. Rattie. (Incorporated by reference to Exhibit 10.9 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
10.21	Purchase and Sale Agreement, dated August 23, 2012, by and among QEP Energy Company, as purchaser, and Helis Oil & Gas Company, L.L.C., as seller. (Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on October 30, 2012.)
10.22	Purchase and Sale Agreement, dated August 23, 2012, by and among QEP Energy Company, as purchaser, and Black Hills Exploration and Production, Inc., Unit Petroleum Company, Sundance Energy, Inc., Highline Exploration, Inc., Houston Energy, L.P., Nisku Royalty, LP, Empire Oil Company and Kent M. Lynch, as sellers. (Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on October 30, 2012.)
10.23	Stipulation and Agreement of Settlement, filed February 13, 2013, in the U.S. District Court for the Western District of Oklahoma. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on February 15, 2013.)
10.24	Contribution, Conveyance and Assumption Agreement, dated as of August 14, 2013, by and among QEP Midstream Partners, LP, QEP Midstream Partners GP, LLC, QEP Field Services Company and QEP Midstream Partners Operating, LLC, incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on August 16, 2013. (Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 5, 2013.)
10.25	Credit Agreement, dated as of August 14, 2013, among QEP Midstream Partners Operating, LLC, as the borrower, QEP Midstream Partners, LP, as the parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lenders from time to time party thereto. (Incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 5, 2013.)
10.26+	QEP Resources, Inc. Basic Executive Severance Compensation Plan, dated effective as of January 20, 2014. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on January 23, 2014.)
10.27+	QEP Resources, Inc. Form of Restricted Stock Agreement for restricted stock granted to certain key executives. (Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on January 23, 2014.)

10.28+	QEP Resources, Inc. Form of Nonqualified Stock Option Agreement for stock options granted to certain key executives. (Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on January 23, 2014.)
10.29+	Amendment to Certain Stock Option Agreements Under the QEP Resources, Inc. 2010 Long-Term Stock Incentive Plan adopted January 20, 2014. (Incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on January 23, 2014.)
10.30+	QEP Midstream Partners, LP 2013 Long-Term Incentive Plan. (Incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 5, 2013.)
10.31+	Form of QEP Midstream Partners, LP 2013 Long-Term Incentive Plan Phantom Unit Award Agreement. (Incorporated by reference to Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 5, 2013.)
10.32+	Omnibus Agreement, dated as of August 14, 2013, by and among QEP Midstream Partners, LP, QEP Midstream Partners GP, LLC, QEP Resources, Inc., QEP Field Services Company and QEP Midstream Partners Operating, LLC. (Incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 5, 2013.)
10.33+	Form of Indemnification Agreement for directors and officers. (Incorporated by reference to Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 5, 2013.)
10.34	Cooperation Agreement, dated February 23, 2014, by and between JANA Partners LLC and QEP Resources, Inc. (Incorporated by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on February 25, 2014).
10.35	Purchase and Sale Agreement, dated December 6, 2013, by and among QEP Energy Company, as purchaser, and EnerVest Holding, L.P., EnerVest Energy Institutional Fund XXI-A, L.P., EnerVest Energy Institutional Fund XII-WIB, L.P., and EnerVest Energy Institutional Fund XII-WIC, L.P., as sellers, as amended by First Amendment to Purchase and Sale Agreement, dated January 31, 2014, by and between EnerVest Holding, L.P. and QEP Energy Company, and Second Amendment to Purchase and Sale Agreement, dated February 14, 2014, by and between EnerVest Holding, L.P. and QEP Energy Company. (Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2014, filed with the Securities and Exchange Commission on May 7, 2014.)
10.36	Purchase and Sale Agreement, dated May 2, 2014, between QEP Energy Company, as seller, and Cimarex Energy Co., as buyer. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on May 8, 2014.)
10.37	Purchase and Sale Agreement, dated May 5, 2014, between QEP Energy Company, as seller, and EnerVest Energy Institutional Fund XIII-A, L.P., EnerVest Energy Institutional Fund XIII-WIB, L.P., EnerVest Energy Institutional Fund XIII-WIC, L.P., and FourPoint Energy, LLC, as buyer, and EnerVest Ltd. (Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K file with the Securities and Exchange Commission on May 8, 2014.)
10.38	Purchase and Sale Agreement, dated May 7, 2014, by and among QEP Field Services Company, QEP Midstream Partners GP, LLC, and QEP Midstream Partners Operating LLC, and QEP Midstream Partners, LP. (Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on May 8, 2014.)
10.39	Membership Interest Purchase Agreement, dated as of October 19, 2014, by and between QEP Field Services Company, as seller, and Tesoro Logistics LP, as purchaser (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on October 20, 2014), as amended by Amendment No. 1 to Membership Interest Purchase Agreement, dated as of December 2, 2014, by and between QEP Field Services Company and Tesoro Logistics LP (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on December 4, 2014.)
10.40	Guaranty, dated December 2, 2014, by QEP Resources, Inc. in favor of Tesoro Logistics LP. (Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on December 4, 2014.)
10.41*+	Form of Performance Share Unit Award Agreement under the QEP Resources, Inc. Cash Incentive Plan, for awards to executive officers through 2014.
10.42*+	Form of Performance Share Unit Award Agreement under the QEP Resources, Inc. Cash Incentive Plan, for awards to executive officers after 2014.
12.1*	Ratio of earnings to fixed charges.
21.1*	Subsidiaries of the Company.
23.1*	Consent of Independent Registered Public Accounting Firm - PricewaterhouseCoopers LLP.

23.2*	Consent of Independent Petroleum Engineers and Geologists - Ryder Scott Company, L.P.
23.3*	Consent of Independent Petroleum Engineers and Geologists - DeGolyer and MacNaughton
24*	Power of Attorney
31.1*	Certification signed by Charles B. Stanley, QEP Resources, Inc., Chairman, President and Chief Executive Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification signed by Richard J. Doleshek, QEP Resources, Inc. Executive Vice President, Chief Financial Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification signed by Charles B. Stanley and Richard J. Doleshek, QEP Resources, Inc. Chairman, President and Chief Executive Officer and Executive Vice President, Chief Financial Officer, respectively, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Qualifications and Report of Independent Petroleum Engineers and Geologists - Ryder Scott Company, L.P.
99.2*	Qualifications and Report of Independent Petroleum Engineers and Geologists - DeGolyer and MacNaughton
101.INS**	XBRL Instance Document
101.SCH**	XBRL Schema Document
101.CAL**	XBRL Calculation Linkbase Document
101.LAB**	XBRL Label Linkbase Document
101.PRE**	XBRL Presentation Linkbase Document
101.DEF**	XBRL Definition Linkbase Document

* Filed herewith

** These interactive data files are furnished and deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities Act of 1934, as amended, and otherwise are not subject to liability under those sections.

\+ Indicates a management contract or compensatory plan or arrangement

(c) **Financial Statement Schedule:**

QEP RESOURCES, INC.
Schedule of Valuation and Qualifying Accounts

Description	Beginning Balance	Amounts charged (credited) to expense	Deductions for accounts written off and other	Ending Balance
		(in millions)		
Year ended December 31, 2014				
Allowance for bad debts	**$ 2.2**	**$ 2.1**	**$ 0.3**	**$ 4.6**
Year ended December 31, 2013				
Allowance for bad debts	2.4	0.1	(0.3)	2.2
Year ended December 31, 2012				
Allowance for bad debts	1.3	1.3	(0.2)	2.4

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on February 24, 2015.

QEP RESOURCES, INC.
(Registrant)

/s/ Charles B. Stanley
Charles B. Stanley,
Chairman, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 24, 2015.

/s/ Charles B. Stanley Charles B. Stanley	Chairman, President and Chief Executive Officer (Principal Executive Officer)
/s/ Richard J. Doleshek Richard J. Doleshek	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ Alice B. Ley Alice B. Ley	Vice President, Controller and Chief Accounting Officer (Principal Accounting Officer)
*Charles B. Stanley	Chairman of the Board; Director
*Phillips S. Baker, Jr.	Director
*L. Richard Flury	Director
*David Trice	Director
*Robert E. McKee III	Director
*M. W. Scoggins	Director
*Julie A. Dill	Director
*Robert F. Heinemann	Director
*William L. Thacker III	Director
February 24, 2015	*By /s/ Charles B. Stanley Charles B. Stanley, Attorney in Fact

Exhibit 10.6

QEP RESOURCES, INC.

DEFERRED COMPENSATION WRAP PLAN

incorporating the:

Deferred Compensation Program
401(k) Supplemental Program

QEP RESOURCES, INC.
DEFERRED COMPENSATION WRAP PLAN

ARTICLE 1
INTRODUCTION

1.1 Purpose. QEP Resources, Inc. hereby amends this QEP Resources, Inc. Deferred Compensation Wrap Plan (the "Plan" or "Wrap Plan"). This Plan was created in order to provide specified benefits to a select group of management and highly compensated employees and to allow such employees to defer the receipt of compensation. The Plan consists of a common Deferred Compensation Wrap Plan containing definitions and other operative provisions and two separate component Programs - the Deferred Compensation Program and the 401(k) Supplemental Program.

1.2 Status of Plan. This Plan and its component Programs are intended to constitute two unfunded, nonqualified deferred compensation arrangements for the purpose of providing deferred compensation to "a select group of management or highly-compensated employees" within the meaning of Sections 201(2), 301(a)(3), and 401(a)(1) of the Employee Retirement Income Security Act of 1974, as amended. The Plan and its component Programs are also intended to comply with Section 409A of the Internal Revenue Code of 1986, as amended, and the regulations and guidance promulgated thereunder. Finally, each of the component Programs is intended to qualify as a separate "plan, program, or arrangement" for purposes of 4 U.S.C. 114, thus making payments under the 401(k) Supplemental Program subject to state income tax solely of the state in which the recipient of the payment resides or is domiciled at the time payment is made. Notwithstanding any other provision herein, this Plan and its component Programs shall be interpreted, operated and administered in a manner consistent with these intentions.

ARTICLE 2
DEFINITIONS

For purposes of the Plan and each component Program established under the Plan, the following terms or phrases shall have the following indicated meanings, unless the context clearly requires otherwise:

2.1 "401(k) Supplemental Program" means the component benefit program of this Plan attached hereto as Exhibit B.

2.2 "Account" or "Account Balance" means, for each Participant, the account or accounts established for his or her benefit under each Program, which records the credit on the records of the Employer equal to the amounts set aside under the Program and the deemed earnings, if any, credited to such account. The Account Balance shall be a bookkeeping entry only and shall be used solely as a device for the measurement and determination of the amounts to be paid to a Participant, or his or her designated Beneficiary, pursuant to this Plan and its component Programs.

2.3 "Affiliated Company" means any entity that is treated as the same employer as the Company under Sections 414(b), (c), (m), or (o) of the Code, any entity required to be aggregated with the Company pursuant to regulations adopted under Code Section 409A, or any entity otherwise designated as an Affiliated Company by the Company.

2.4 "Beneficiary" means that person or persons who become entitled to receive a distribution of benefits under the component Programs in the event of the death of a Participant prior to the distribution of all benefits to which he or she is entitled.

2.5 "Board" means the Board of Directors of the Company.

2.6 "Change in Control" shall be deemed to have occurred if: (i) any individual, entity, or group (within the meaning of Section 13(d)(3) or 14(d)(2) of the Securities Exchange Act of 1934 (the "Exchange Act")) other than a trustee or other fiduciary holding securities under an employee benefit plan of the Company, is or becomes the beneficial owner (as such term is used in Rule 13d-3 under the Exchange Act) of securities of the Company representing 30 percent or more of the combined voting power of the Company; or (ii) the following individuals cease for any reason to constitute a majority of the number of directors then serving: individuals who, as of the Effective Date, constitute the Company's Board of Directors and any new director (other than a director whose initial assumption of office is in connection with an actual or threatened election contest, including but not limited to a consent solicitation, relating to the election of directors of the Company) whose appointment or election by the Board or nomination for election by the Company's stockholders was approved or recommended by a vote of at least two-thirds of the directors then still in office who either were directors on the Effective Date, or whose appointment, election or nomination for election was previously so approved or recommended; or (iii) there is consummated a merger or consolidation of the Company or any direct or indirect subsidiary of the Company with any corporation, other than a merger or consolidation that would result in the voting securities of the Company outstanding immediately prior to such merger or consolidation continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity or any parent thereof) at least 60 percent of the combined voting power of the securities of the Company or such surviving entity or its parent outstanding immediately after such merger or consolidation, or a merger or consolidation effected to implement a recapitalization of the Company (or similar transaction) in which no person is or becomes the beneficial owner, directly or indirectly, of securities of the Company representing 30 percent or more of the combined voting power of the Company's then outstanding securities; or (iv) the Company's stockholders approve a plan of complete liquidation or dissolution of the Company or there is consummated the sale or disposition by the Company of all or substantially all of the Company's assets, other than a sale or disposition by the Company of all or substantially all of the Company's assets to an entity, at least 60 percent of the combined voting power of the voting securities of which are owned by the stockholders of the Company in substantially the same proportions as their ownership of the Company immediately prior to such sale. In addition, if a Change in Control constitutes a payment event with respect to any payment under the Plan which provides for the deferral of compensation and is subject to Section 409A of the Code, the transaction or event described in clauses (i), (ii), (iii) and (iv) with respect to such payment must also constitute a "change in control event," as defined in Treasury Regulation Section 1.409A-3(i)(5) before any such payment can be made.

2.7 "Code" means the Internal Revenue Code of 1986, as amended.

2.8 "Committee" means the Compensation Committee of the Board or such other person or entity to which any responsibilities may be delegated by such Committee.

2.9 "Common Stock" means the no par value common stock of the Company.

2.10 "Company" means QEP Resources, Inc., a corporation organized and existing under the laws of the State of Delaware, or its successor or successors.

2.11 "Compensation" means:

(a) Deferred Compensation Program. For purposes of the Deferred Compensation Program, the total earnings paid by an Employer to an Employee and properly reportable on IRS Form W-2 for an applicable Plan Year (including payments under annual incentive compensation plans) and all amounts that are not included in such Employee's gross income for federal income tax purposes solely on account of his or her election to have compensation reduced pursuant to the Plan, a qualified cash or deferred arrangement described in Section 401(k) of the Code, a cafeteria plan as defined in Section 125 of the Code, or a qualified transportation fringe benefit plan as defined in Section 132(f)(4) of the Code, but excluding the following forms of compensation, unless otherwise determined by the Committee: the Employer's cost for any public or private employee benefit plan, any income recognized by the Employee as a result of exercising stock options, moving expenses, loan forgiveness, welfare benefits, and severance payments.

(b) 401(k) Supplemental Program. For purposes of the 401(k) Supplemental Program, the same meaning as Benefit Compensation as defined in the Investment Plan, but (i) without regard to the Compensation Limit and (ii) including all amounts that are not included in such Employee's gross income for federal income tax purposes solely on account of his or her election to make Deferral Contributions to the 401(k) Supplemental Program.

2.12 "Compensation Limit" means the annual limit of compensation that may be taken into account for purposes of providing benefits under a tax-qualified retirement plan pursuant to Section 401(a)(17) of the Code, as adjusted from time to time.

2.13 "Deferral Contributions" means that portion of a Participant's Compensation that is deferred by a Participant pursuant to the Programs.

2.14 "Deferred Compensation Program" means the component benefit program of this Plan attached hereto as Exhibit A.

2.15 "Deferred Compensation Sub-Account" means the sub-account described in Section 5.1 of the Deferred Compensation Program.

2.16 "Disability" means a condition that renders a Participant unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment which can be expected to result in death or can be expected to last for a continuous period of not less than 12 months, as described in Treas. Reg. Section 1.409A-3(i)(4)(i)(A). A Participant shall not be considered to be disabled unless the Participant furnishes proof of the existence of such disability in such form and manner as may be required by regulations promulgated under, or applicable to, Code Section 409A.

2.17 "Eligible Employee" means any Employee who meets the eligibility requirements set forth in the applicable Program.

2.18 "Employee" means any individual who is among a select group of management or highly compensated employees (as determined in accordance with Section 3401(c) of the Code and the Treasury Regulations thereunder) of an Employer.

2.19 "Employer" means the Company and each Affiliated Company that consents to the adoption of the Plan.

2.20 "ERISA" shall mean the Employee Retirement Income Security Act of 1974, as amended.

2.21 "Fair Market Value" means the closing benchmark price of the Company's Common Stock as reported on the composite tape of the New York Stock Exchange for any given valuation date, or if the Common Stock shall not have been traded on such date, the closing price on the next preceding day on which a sale occurred.

2.22 "Investment Plan" means the QEP Resources, Inc. Employee Investment Plan, as amended from time to time, or any successor plan.

2.23 "Matching Contributions" means Employer contribution amounts credited to Participants under the Deferred Compensation Program and 401(k) Supplemental Program in addition to (and made on account of) the Participants' Deferral Contributions under such Programs.

2.24 "Matching Contribution Sub-Account" means the sub-account described in Section 5.1 of the Deferred Compensation Program.

2.25 "Participant" means any individual who has commenced participation in the Plan and any of its component Programs in accordance with Article 3.

2.26 "Plan" or "Wrap Plan" means this QEP Resources, Inc. Deferred Compensation Wrap Plan, as amended or restated from time to time.

2.27 "Plan Year" means the calendar year.

2.28 "Program" means the Deferred Compensation Program and the 401(k) Supplemental Program, or either of them, as the context may require.

2.29 "Separation from Service" means a Participant's termination or deemed termination from employment with the Employer. For purposes of determining whether a Separation from Service has occurred, the employment relationship is treated as continuing intact while the Participant is on military leave, sick leave or other bona fide leave of absence if the period of such leave does not exceed six months, or if longer, so long as the Participant retains a right to reemployment with his Employer under an applicable statute or by contract. For this purpose, a leave of absence constitutes a bona fide leave of absence only if there is a reasonable expectation that the Participant will return to perform services for the Employer. If the period of leave exceeds six months and the Participant does not retain a right to reemployment under an applicable statute or by contract, the employment relationship will be deemed to terminate on the first date immediately following such six-month period. For purposes of this Plan, a Separation from Service occurs at the date as of which the facts and circumstances indicate either that, after such date: (i) the Participant and Employer reasonably anticipate the Participant will perform no further services for the Company or an Affiliate (whether as an employee or an independent contractor), or (ii) that the level of bona fide services the Participant will perform for the Company or any Affiliate (whether as an employee or independent contractor) will permanently decrease to no more than 20 percent of the average level of bona fide services performed over the immediately preceding 36-month period or, if the Participant has been providing services to the Company or an Affiliate for less than 36 months, the full period over which the Participant has rendered services, whether as an employee or independent contractor. The determination of whether a Separation from Service has occurred shall be governed by the provisions of Treasury Regulation section 1.409A-1, as amended, taking into account the objective facts and circumstances with respect to the level of bona fide services performed by the Participant after a certain date.

2.30 "Unforeseeable Emergency" means a severe financial hardship to a Participant resulting from (a) an illness or accident of the Participant, the Participant's spouse, Beneficiary or dependent (within the meaning of section 152 of the Code, without regard to section 152(b)(1), (b)(2) and (d)(1)(B)); (b) the loss of the Participant's property due to casualty; or (c) other similar extraordinary and unforeseeable circumstances arising as a result of events beyond the control of the Participant.

ARTICLE 3

ELIGIBILITY; PARTICIPATION

3.1 Eligibility. Eligibility to participate in the Plan shall be determined for each program as provided in Article 2 thereof.

3.2 Enrollment and Commencement of Deferrals. Except as provided below with regard to automatic enrollment in the 401(k) Supplemental Program, each Eligible Employee who wishes to participate in the Plan for a Plan Year must make an irrevocable election to make Deferral Contributions for the Plan Year by timely completing, executing, and returning to the Committee such election forms or other enrollment materials, including electronic enrollment, as the Committee requires on or prior to December 31st of the prior Plan Year, or such other earlier date as the Committee establishes in its sole and absolute discretion.

If an Eligible Employee fails to timely complete, execute and return such election forms or other enrollment materials, the Eligible Employee shall be automatically enrolled in the 401(k) Supplemental Program as provided in Section 4.1(a), but shall not participate in the Deferred Compensation Program until the first day of the first Plan Year beginning after the date on which he or she timely completes, executes and returns such election forms or other enrollment materials to the Committee.

3.3 Failure of Eligibility. If the Committee determines, in its sole and absolute discretion, that any Participant should no longer qualify to participate, the Participant shall cease to be an active Participant in the Plan and future contributions to the Plan made by or on behalf of the Participant shall cease as of the date of such determination by the Committee. The Committee's determination hereunder shall be final and binding on all persons.

ARTICLE 4
ELECTIONS

4.1 Deferral Elections. Any deferral election under the Plan and its component Programs shall be made in accordance with Section 409A(a)(4)(B) of the Code and the regulations thereunder.

(a) First Year of Plan Participation. In connection with a Participant's enrollment in the Plan pursuant to Section 3.2, the Participant shall make an irrevocable election to defer Compensation in accordance with the terms of the component Programs for which he or she is eligible, which election shall apply to the Plan Year in which the Participant commences participation. A Participant may elect to defer Compensation only with respect to services performed for periods following the date of such election. The Participant's initial deferral election under this Section 4.1(a) shall continue to apply for all succeeding Plan Years unless and until revoked or modified pursuant to Section 4.1(b), below. If the Participant fails to timely complete, execute and return such forms or other enrollment materials as required by the Committee in accordance with Section 3.2, then the Participant shall be deemed to have elected to make the Deferral Contributions permitted under the 401(k) Supplemental Program for the Plan Year in which the Participant commences participation and shall not be permitted to make any Deferral Contributions under the Deferred Compensation Program for such Plan Year.

(b) Subsequent Plan Years. For each succeeding Plan Year, the Participant may, prior to December 31st of the immediately preceding Plan Year (or such earlier deadline as is established by the Committee in its sole discretion) make an irrevocable election to initially defer Compensation under the Deferred Compensation Program for succeeding Plan Years, or to modify or revoke his or her existing elections to defer Compensation under either or both of the Programs for succeeding Plan Years. All such elections shall be made in accordance with the terms of the Programs and shall remain in effect for all succeeding Plan Years unless timely revoked or modified by the Participant in accordance with this Section.

Any such modification shall apply prospectively only and shall not apply to Compensation previously deferred under either or both of the Programs.

(c) Performance-Based Compensation. The Committee may, in its sole discretion, determine that an irrevocable deferral election pertaining to Compensation that constitutes “performance-based compensation” (as defined in Treas. Reg. Section 1.409A-1(e)) may be made no later than six (6) months before the end of the performance service period, provided that the Participant performs services continuously from the later of the beginning of the performance period or the date upon which the performance criteria are established through the date upon which the Participant makes a deferral election for such compensation; provided, further that in no event shall an election to defer performance-based compensation be permitted after such compensation has become readily ascertainable. Any deferral election under this Section 4.1(c) shall be made in accordance with Treas. Reg. Section 1.409A-2(a)(8).

(d) Compensation Subject to Risk of Forfeiture. With respect to Compensation (i) to which a Participant has a legally binding right to payment in a subsequent year, and (ii) that is subject to a forfeiture condition requiring the Participant’s continued services for a period of at least twelve (12) months from the date the Participant obtains the legally binding right to such payment, the Committee may, in its sole discretion, determine that an irrevocable election to defer such Compensation may be made no later than the 30th day after the Participant obtains the legally binding right to the Compensation, provided that the election is made at least twelve (12) months in advance of the earliest date at which the forfeiture condition could lapse. Any deferral election under this Section 4.1(d) shall be made in accordance with Treas. Reg. Section 1.409A-2(a)(5).

Any election(s) made in accordance with this Section shall be irrevocable; provided, however, that if the Committee permits Participants to make a deferral election for “performance-based compensation” or “compensation subject to a substantial risk of forfeiture” by the deadline(s) described above, it may, in its sole discretion, and in accordance with Code Section 409A and related Treasury guidance or regulations, permit a Participant to subsequently change his or her elections for such Compensation no later than the deadlines established by the Committee pursuant to Section 4.1(c) or 4.1(d), above.

4.2 Elections as to Time and Form of Payment. In connection with a Participant’s enrollment in the Plan pursuant to Section 3.2, the Participant shall also make the following elections with respect to each Program under the Plan:

(a) Deferred Compensation Program. If eligible to participate in the Deferred Compensation Program for the Plan Year in which the Participant commences participation under the Plan, the Participant shall make an irrevocable election (from the options available under Article 6 below) as to the time and form of payment of all deferrals (in the form of Deferral and/or Matching Contributions) credited to his or her Account under the Deferred Compensation Program for such Plan Year (including earnings thereon). If the Participant fails to make such election, or such election does not meet the requirements of Code Section 409A and related Treasury guidance or regulations, the Participant shall be deemed to have elected to receive a lump sum distribution as soon as legally and administratively practicable following the earliest to occur of the Participant’s (i) Separation from Service, (ii) Disability, or (iii) death. Except in the case of an election to receive an in-service distribution pursuant to Section 6.1(b)(iii), the Participant’s election (or deemed election) shall continue to apply for succeeding Plan Years unless and until the election is modified pursuant to Section 4.2(c), below.

(b) 401(k) Supplemental Program. The Participant shall make an irrevocable election as to the time and form of payment of all deferrals (in the form of Deferral and/or Matching Contributions) credited to his or her Account Balance under the 401(k) Supplemental Program from the options available under Section 6 below. If the Participant fails to make such election, or if such election does not meet the requirements of Code Section 409A and related Treasury guidance or regulations, the Participant shall be deemed to have elected to receive a lump-sum distribution as soon as legally and administratively practicable following the earliest to occur of the Participant's (i) Separation From Service, (ii) Disability, or (iii) death.

(c) A Participant may make an irrevocable election to modify his or her existing elections as to the time and form of payment of any future Deferral or Matching Contributions credited to his or her Account Balance (and related earnings) under either or both of the Programs for succeeding Plan Years. Such election shall be made in accordance with the terms of the Deferred Compensation Program and 401(k) Supplemental Program and Article 6 below, and except in the case of an election to receive an in-service distribution pursuant to Section 6.1(b)(iii), which election must be made separately for each Plan Year, the election shall remain in effect for all succeeding Plan Years unless and until timely modified by the Participant in accordance with this Section. Any such modification shall apply prospectively only and shall not apply to Deferral or Matching Contributions previously credited under the Program (or any earnings thereon).

4.3 Election Forms. All elections shall be made on forms, including electronic forms, provided by the Committee and must be filed with the Company's Vice President of Human Resources in order to be valid.

ARTICLE 5
ACCOUNT STATEMENTS

At least once a year within 60 days after the end of each Plan Year, a statement shall be sent to each Participant showing his or her Account Balance for each Program as of the last day of the Plan Year. The statement shall also include the Deferral Contributions made by the Participant to each Program for the Plan Year, along with any Matching Contributions credited to the Participant's Account Balances and the investment gains or losses (including reinvested dividends) credited during the Plan Year.

ARTICLE 6
DISTRIBUTIONS

6.1 Permissible Times and Forms of Payments. A Participant may elect to receive his or her Account under the Deferred Compensation Program or his or her Account under the 401(k) Supplemental Program pursuant to an election form filed in accordance with Article 4 at the following times and in the following forms:

(a) Time of Distribution. A Participant may elect to receive a distribution as of the date of, or at a designated anniversary date following, the first to occur of the Participant's Disability, Separation from Service, death or in the case of a distribution from the Participant's Deferred Compensation Sub-Account, at a designated time or times specified by the Participant in his or her election forms, which shall not be earlier than 24 months from the date of deferral of the amount to be distributed.

(b) Form of Distribution. A Participant may elect to receive a distribution of his or her Account in any of the following forms:

(i) a single lump sum;

(ii) up to ten (10) annual installments; or

(iii) in the case of an in-service distribution from a Participant's Deferred Compensation Sub-Account a single lump sum of the entire Account Balance attributable to the Participant's Deferral Contributions made in one or more Plan Years, as designated by the Participant.

(c) Subsequent Deferrals. Notwithstanding an actual or deemed election as to the timing of the distribution of a Participant's Account, at such times and in such manner as the Committee may determine, a Participant may make an irrevocable election to delay the payment, or the commencement of payment, of his or her Account, but only if such election (i) is made not less than 12 months before the date the payment or commencement of installment payments is scheduled to be paid or to begin; (ii) shall not take effect until at least 12 months after the date the election is made; and (iii) relating to a payment not being made on account of death, Disability or an Unforeseeable Emergency, delays the payment or commencement of payments for a period of at least five years from the date the payment or series of payments was scheduled to be paid or begin.

(d) Unforeseeable Emergency Distributions. A participant may request that a distribution of amounts credited to his Account may be made due to an Unforeseeable Emergency.

(i) In no event shall a distribution due to an Unforeseeable Emergency exceed the balance of the Participant's Account, determined as of the end of the month immediately preceding the date of the distribution, less any amounts distributed from or charged to the Participant Account since such date. The Committee may promulgate uniform rules regarding the effective date of any distribution, minimum amounts to be distributed and the frequency of distributions.

(ii) A distribution may be made pursuant to this Section 6.1(d) due to an Unforeseeable Emergency only if the Participant satisfies the Committee that the Participant has an Unforeseeable Emergency and that the distribution is reasonably necessary in order to satisfy the Unforeseeable Emergency.

(iii) A distribution because of an Unforeseeable Emergency may be made for one of the reasons listed in subparagraphs (A) through (C) of this paragraph (iii):

(A) Medical expenses, including non-refundable deductibles and the cost of prescription drugs; or

(B) The need to pay for funeral expenses of a spouse, Beneficiary or a dependent as defined; or

(C) The need to prevent the imminent eviction of the Participant from his principal residence or foreclosure on the mortgage on the Participant's principal residence.

(iv) A distribution will be considered to be reasonably necessary to satisfy an emergency need of a Participant only if the need may not be satisfied from other resources that are reasonably available to the Participant and the distribution does not exceed the amount needed to satisfy the need. The Committee shall consider all relevant facts and circumstances in determining whether a distribution is necessary in order to satisfy an emergency need. Generally, a distribution shall be deemed necessary if the Participant demonstrates to the Committee that the need cannot be relieved through reimbursement or compensation from insurance or otherwise, by the liquidation of the Participant's assets (to the extent that such liquidation would not itself cause severe financial hardship) or by cessation of Deferral Contributions under the Plan. A distribution will be deemed to be reasonably necessary to satisfy the emergency need of a Participant only if the distribution is not in excess of the amount reasonable necessary to satisfy the emergency need of the Participant (which may include amounts necessary to pay any federal, state, local or foreign income taxes or penalties reasonably anticipated to result from the distribution).

6.2 Change in Control. Notwithstanding any election made by the Participant under Section 6.1, in the event of a Change in Control, all amounts then credited to the Participant's Account shall be distributed to the Participant in a single lump sum within 60 days following the date of such Change in Control.

6.3 Calculation of Distributions.

(a) Lump Sum. All lump sum distributions shall be based on the value of the Participant's Account as of a valuation date as soon as administratively feasible preceding the date distribution is made, in accordance with rules established by the administrator.

(b) Installment Distributions. Under an installment payout, the amount to be distributed in each installment payment shall be determined by dividing the value of the Participant's Accounts being paid in installments as of a valuation date preceding the date of each distribution by the number of installment payments remaining to be made, in accordance with rules established by the administrator. In the event of the death of the Participant prior to the full payment of his Accounts being paid in installments, payments will continue to be made to his Beneficiary in the same manner as would have been payable to the Participant.

6.4 Six-Month Delay. Notwithstanding anything to the contrary in the Plan, no distribution shall be made to a Participant under the Plan on account of the Participant's Separation from Service during the 6-month period following such Separation from Service to the extent that the Company determines that the Participant is a "specified employee" (as defined in Section 409A(a)(2)(B)(i) of the Code and the Treasury Regulations thereunder) at the time of such Separation from Service and that paying such amounts at the time or times indicated in the Plan would be a prohibited distribution under Section 409A(a)(2)(B)(i) of the Code. If the payment of any such amounts is delayed as a result of the previous sentence, then on the first business day following the end of such 6-month period (or such earlier date upon which such amount can be paid under Section 409A of the Code without being subject to such additional taxes, including as a result of the Participant's death), a lump-sum distribution shall be made to the Participant under the Plan equal to the cumulative amount that would have otherwise been payable to the Participant during such 6-month period.

6.5 Method of Payment. All payments under the Plan shall be made in cash.

ARTICLE 7
ADMINISTRATION

7.1 Committee to Administer and Interpret Plan and Component Programs. The Committee or its designee shall administer the Plan and its component Programs and shall have all discretion and power necessary for that purpose. The Committee shall have the discretion, authority, and power to (i) make, amend, interpret, and enforce all appropriate rules and regulations for the administration of the Plan and its component Programs and (ii) decide or resolve any and all questions that may arise in connection with this Plan and its component Programs, including interpretations of the Plan and its component Programs and determinations of eligibility to participate and to receive distributions under the Plan and its component Programs. Any individual serving on the Committee, or anyone delegated responsibilities by the Committee, shall not vote or act on any matter relating solely to himself. When making a determination or calculation, the Committee shall be entitled to rely on information supplied by a Participant, Beneficiary, or the Employer, as the case may be. The Committee shall maintain all records of the Plan and its component Programs.

7.2 Agents. In the administration of this Plan and its component Programs, the Committee may, from time to time, employ agents (including officers and other employees of the Company) and delegate to them such administrative duties as it sees fit (including acting through a duly appointed representative) and may from time to time consult with counsel who may be counsel to the Company.

7.3 Binding Effect of Decisions. The decision or action of the Committee with respect to any question arising out of or in connection with the administration, interpretation and application of the Plan and its component Programs and the rules and regulations promulgated hereunder shall be final and conclusive and binding upon all persons having any interest in the Plan and its component Programs.

7.4 Indemnity of Committee. The Company shall indemnify and hold harmless the members of the Committee and any employee to whom duties of the Committee may be delegated against any and all claims, losses, damages, expenses or liabilities arising from any action or failure to act with respect to this Plan and its component Programs, except in the case of willful misconduct by the Committee, any of its members, or any such employee.

7.5 Agent for Legal Process. The Committee shall be agent of the Plan and its component Programs for service of all legal process.

ARTICLE 8
CLAIMS PROCEDURE

8.1 Filing a Claim. All claims under this Plan and its component Programs shall be filed in writing or electronically by the Participant, his or her Beneficiary, or the authorized representative of either, by completing the procedures that the Committee requires. The procedures shall be reasonable and may include the completion of forms and the submission of documents and additional information. All claims shall be filed in writing or electronically with the Committee according to the Committee's procedures no later than one year after the occurrence of the event that gives rise to the claim. If the claim is not filed within the time described in the preceding sentence, the claim shall be barred.

8.2 Review of Initial Claim.

(a) Initial Period for Review of the Claim. The Committee shall review all materials and shall decide whether to approve or deny the claim. If a claim is denied in whole or in part, written notice of denial shall be furnished by the Committee to the claimant within a reasonable time after the claim is filed but not later than ninety (90) days after the Committee receives the claim. The notice shall set forth the specific reason(s) for the denial, reference to the specific Plan or Program provisions on which the denial is based, a description of any additional material or information necessary for the claimant to perfect his or her claim and an explanation of why such material or information is necessary, and a description of the Plan's review procedures, including the applicable time limits and a statement of the claimant's right to bring a civil action under ERISA section 502(a) following a denial of the appeal.

(b) Extension. If the Committee determines that special circumstances require an extension of time for processing the claim, it shall give written notice to the claimant and the extension shall not exceed ninety (90) days. The notice shall be given before the expiration of the ninety (90) day period described in Section 8.2(a) above and shall indicate the special circumstances requiring the extension and the date by which the Committee expects to render its decision.

8.3 Appeal of Denial of Initial Claim. The claimant may request a review upon written application, may review pertinent documents, and may submit issues or comments in writing. The claimant must request a review within a reasonable period of time prescribed by the Committee. In no event shall such a period of time be less than sixty (60) days.

8.4 Review of Appeal.

(a) Initial Period for Review of the Appeal. The Committee shall conduct all reviews of denied claims and shall render its decision within a reasonable time, but not to exceed sixty (60) days from the receipt of the appeal by the Committee. The claimant shall be notified of the Committee's decision in a notice, which shall set forth the specific reason(s) for the denial, reference to the specific Plan or Program provisions on which the denial is based, a statement that the claimant is entitled to receive, upon request and free of charge, reasonable access to and copies of all documents, records, and other information relevant to the claimant's claim, and a statement of the claimant's right to bring a civil action under ERISA section 502(a) following a denial of the appeal.

(b) Extension. If the Committee determines that special circumstances require an extension of time for reviewing the appeal, it shall give written notice to the claimant and the extension shall not exceed sixty (60) days. The notice shall be given before the expiration of the sixty (60) day period described in Section 8.4(a) above and shall indicate the special circumstances requiring the extension and the date by which the Committee expects to render its decision.

8.5 Form of Notice to Claimant. The notice to the claimant shall be given in writing or electronically and shall be written in a manner calculated to be understood by the claimant. If the notice is given electronically, it shall comply with the requirements of Department of Labor Regulation Section 2520.104b-1(c)(1)(i), (iii), and (iv).

8.6 Discretionary Authority of Committee. The Committee shall have full discretionary authority to determine eligibility, status, and the rights of all individuals under the Plan and its component Programs, to construe any and all terms of the Plan and its component Programs, and to find and construe all facts.

ARTICLE 9
AMENDMENT AND TERMINATION OF PLAN

The Board may at any time amend, modify, or terminate this Plan and its component Programs; provided, however, that no such amendment may reduce any Participant's Account Balances under the Plan or any component Program as it existed prior to the date of such amendment or termination.

ARTICLE 10
MISCELLANEOUS

10.1 Source of Payments. Each participating Employer will pay all benefits for its Employees arising under this Plan and its component Programs, and all costs, charges and expenses relating to such benefits, out of its general assets.

10.2 No Assignment or Alienation.

(a) General. Except as provided in subsection (b) below, the benefits provided for in this Plan and its component Programs shall not be anticipated, assigned (either at law or in equity), alienated, or be subject to attachment, garnishment, levy, execution or other legal or equitable process. Any attempt by any Participant or any Beneficiary to anticipate, assign or alienate any portion of the benefits provided for in this Plan or its component Programs shall be null and void.

(b) Exception: DRO. The restrictions of subsection (a) shall not apply to a distribution to an "alternate payee" (as defined in Code Section 414(p)) pursuant to a "domestic relations order" ("DRO") within the meaning of Code Section 414(p)(1)(B). The Committee shall have the discretion, power, and authority to determine whether an order is a DRO. Upon a determination that an order is a DRO, the Committee shall direct the Employer to distribute to the alternate payee or payees named in the DRO, as directed by the DRO.

10.3 Beneficiaries. A Participant shall have the right, in accordance with forms and procedures established by the Committee, to designate one or more beneficiaries to receive some or all amounts payable under each of the component Programs after the Participant's death. The Participant need not designate the same Beneficiary for each Program under the Plan. In the absence of an effective beneficiary designation, all payments shall be made to the beneficiary designated by the Participant (or deemed by law to be designated) under the terms of the Investment Plan.

10.4 No Creation of Rights. Nothing in this Plan or its component Programs shall confer upon any Participant the right to continue as an Employee of an Employer. The right of a Participant to receive a cash distribution shall be an unsecured claim against the general assets of his or her Employer. Nothing contained in this Plan or its component Programs nor any action taken hereunder shall create, or be construed to create, a trust of any kind, or a fiduciary relationship between the Company and the Participants, Beneficiaries, or any other persons. All Accounts under the Plan and its component Programs shall be maintained for bookkeeping purposes only and shall not represent a claim against specific assets of any Employer.

10.5 Furnishing Information. A Participant or his or her Beneficiary shall cooperate with the Committee by furnishing any and all information requested by the Committee and take such other actions as may be requested in order to facilitate the administration of the Plan and its component Programs and the payment of benefits thereunder.

10.6 Payments to Incompetents. If the Committee determines in its discretion that a benefit under this Plan or any of its component Programs is to be paid to a minor, a person declared incompetent or to a person incapable of handling the disposition of his or her property, the Committee may direct payment of such benefit to the guardian, legal representative or person having the care and custody of such minor, incompetent or incapable person. The Committee may require proof of minority, incompetence, incapacity or guardianship, as it may deem appropriate prior to distribution of the benefit. Any payment of a benefit shall be a payment for the account of the Participant and the Participant's Beneficiary, as the case may be, and shall be a complete discharge of any liability under the Plan and its component Programs for such payment amount.

10.7 Court Order. The Committee is authorized to make any payments directed by court order in any action in which the Plan or the Committee has been named as a party.

10.8 Code Section 409A Savings Clause. The payments and benefits provided under the Plan and its component Programs are intended to be compliant with the requirements of Section 409A of the Code. Notwithstanding any provision of this Plan to the contrary, including, without limitation, Article 9 hereof, in the event that the Company reasonably determines that any payments or benefits hereunder are not either exempt from or compliant with the requirements of Section 409A of the Code, the Company shall have the right adopt such amendments to this Plan and its component Programs or adopt such other policies and procedures (including amendments, policies and procedures with retroactive effect), or take any other actions, that are necessary or appropriate (i) to preserve the intended tax treatment of the payments and benefits provided hereunder, to preserve the economic benefits with respect to such payments and benefits, and/or (ii) to exempt such payments and benefits from Section 409A of the Code or to comply with the requirements of Section 409A of the Code and thereby avoid the application of penalty taxes thereunder; provided, however, that this Section 10.8 does not, and shall not be construed so as to, create any obligation on the part of the Company to adopt any such amendments, policies or procedures or to take any other such actions or to indemnify any Participant for any failure to do so.

10.9 Attorney Fees; Interest. The Company agrees to pay as incurred, to the full extent permitted by law all legal fees and expenses which a Participant may reasonably incur as a result of any contest (regardless of the outcome thereof) by the Company, the Participant, or others following a Change in Control regarding the validity or enforceability of, or liability under, any provision of this Plan or any guarantee of performance thereof (including as a result of any contest by the Participant about the amount of any payment pursuant to this Plan), plus in each case interest on any delayed payment at the applicable Federal rate provided for in Section 7872(f)(2)(A) of the Code. The foregoing right to legal fees and expenses shall not apply to any contest brought by a Participant (or other party seeking payment under the Plan) that is found by a court of competent jurisdiction to be frivolous or vexatious. To the extent that any payments or reimbursements provided to the Participant under this Section are deemed to constitute compensation to the Participant, such amounts shall be paid or reimbursed reasonably promptly, but not later than December 31 of the year following the year in which the expense was incurred. The amount of any payments or expense reimbursements that constitute compensation in one year shall not affect the amount of payments or expense reimbursements constituting compensation that are eligible for payment or reimbursement in any subsequent year, and the Participant's right to such payments or reimbursement of any such expenses shall not be subject to liquidation or exchange for any other benefit.

10.10 Distribution in the Event of Taxation. If, for any reason, all or any portion of a Participant's benefits under this Plan or any of its component Programs becomes subject to federal income tax with respect to the Participant prior to receipt, a Participant may petition the Committee for a distribution of that portion of his or her benefit that has become taxable, or such lesser amount as may be permitted by Code Section 409A. Upon the grant of such a petition, which grant shall not be unreasonably withheld, the Employer shall distribute to the Participant immediately available funds in an amount equal to the taxable portion of his or her benefit or such lesser amount as may be permitted by Code Section 409A (which amount shall not exceed a Participant's unpaid Account Balances). If the petition is granted, the tax liability distribution shall be made within 90 days of the date when the Participant's petition is granted. Such a distribution shall affect and reduce the benefits to be paid under this Plan and its component Programs. Any distribution under this Section 10.10 must meet the requirements of Code Section 409A and related Treasury guidance or Regulations.

10.11 Governing Law. To the extent not preempted by federal law, this Plan and its component Programs shall be governed by the laws of the State of Colorado without regard to conflicts of law principles.

I hereby certify that this revised QEP Resources, Inc. Deferred Compensation Wrap Plan was duly adopted by the Board of Directors of QEP Resources, Inc. on ______________, 201_.

Executed on this 23 day of February, 2015.

By: /s/ Richard J. Doleshek

Richard J. Doleshek
Executive Vice President and Chief Financial Officer

Exhibit A

DEFERRED COMPENSATION PROGRAM

a component Program of the

QEP Resources, Inc. Deferred Compensation Wrap Plan

QEP RESOURCES, INC.
DEFERRED COMPENSATION PROGRAM

ARTICLE 1
INTRODUCTION

1.1 Establishment of Program. The Company hereby establishes this revised Deferred Compensation Program under the Wrap Plan, as of January 1, 2012. Unless otherwise defined herein, all capitalized terms herein shall the meanings set forth in the QEP Resources, Inc. Deferred Compensation Wrap Plan.

1.2 Purpose. The purposes of the Deferred Compensation Program are (i) to provide Participants with the opportunity to defer receipt of specified portions of their annual Compensation including Bonuses in order to reduce current taxable income and to provide for future financial needs, and (ii) to provide a benefit to each Participant approximately equal to the benefit the Participant would have received under the Investment Plan if the Participant did not elect to defer Compensation under the Deferred Compensation Program but instead contributed an applicable portion of such amount to the Investment Plan.

ARTICLE 2
PARTICIPATION; ELECTIONS

2.1 Participation. An Employee shall be an Eligible Employee for purposes of this Program if he or she is in a salary classification designated by the Committee as eligible to participate in the Program for a Plan Year or is otherwise designated as an Eligible Employee by the Committee.

2.2 Elections. Each Participant shall make elections with regard to the deferral of Compensation and the time and form of payments under the Deferred Compensation Program in accordance with Articles 4 and 6 of the Wrap Plan.

ARTICLE 3
DEFERRAL CONTRIBUTIONS

Each Plan Year, a Participant, electing to defer Compensation under the Deferred Compensation Program for such Plan Year may defer up to a maximum of 50% of his or her Compensation for such Plan Year, or such larger percentage of Compensation or a component thereof as may be designated by the Committee for a Plan Year. For the avoidance of doubt, to the extent permitted by the Committee for a Plan Year, a Participant may make separate deferral elections with respect to separate components of Compensation, in each case within the time periods required under the Wrap Plan and Section 409A of the Code and the Treasury Regulations thereunder.

ARTICLE 4
MATCHING CONTRIBUTIONS

4.1 Determination of Matching Contributions. A Participant who makes Deferral Contributions to the Deferred Compensation Program for a Plan Year may receive a Matching Contribution. The Committee will determine annually the amount, if any, of the Matching Contribution, which, for the avoidance of doubt, may be determined separately for separate components of Deferral Contributions in the discretion of the Committee.

4.2 Vesting. Except with respect to any Deferral Contributions that relate to unvested Compensation, a Participant shall be fully vested at all times in the portion of his or her Account attributable to Deferral Contributions. Any Deferral Contributions that relate to unvested Compensation shall be subject to the same vesting terms, conditions and provisions as applied to the underlying Compensation (or component thereof) to which the Deferral Contributions relate. A Participant shall be vested in the portion of his or her Account attributable to Matching Contributions to the same extent as such Participant is vested in any matching contributions under the Investment Plan, unless otherwise determined by the Committee at the time of making any applicable Matching Contribution.

ARTICLE 5
ACCOUNTS; DEEMED INVESTMENTS

5.1 Accounts. The Committee shall establish an Account for each Participant with at least two sub-accounts as follows:

(a) a Deferred Compensation Sub-Account which shall reflect all Deferral Contributions made by the Participant for each Plan Year, together with any adjustments for income, gain or loss and any payments from such sub-account as provided herein;

(b) a Matching Contribution Sub-Account which shall reflect all Company Matching Contributions made under the Deferred Compensation Program for each Plan Year, together with any adjustments for income, gain or loss and any payments from such sub-account as provided herein.

The Committee shall establish such other sub-accounts as it deems necessary or desirable for the proper administration of the Deferred Compensation Program. Amounts deferred by a Participant under the Deferred Compensation Program shall be credited to the Participant’s Account as soon as administratively practicable after the amounts would have otherwise been paid to the Participant.

5.2 Status of Accounts. Accounts and sub-accounts established hereunder shall be record-keeping devices utilized for the sole purpose of determining benefits payable under the Deferred Compensation Program, and will not constitute a separate fund of assets but shall continue for all purposes to be part of the general, unrestricted assets of the Employer, subject to the claims of its general creditors.

5.3 Deemed Investment of Amounts Deferred.

(a) Deferred Compensation Program. In connection with his or her enrollment in the Deferred Compensation Program, a Participant may elect to have earnings, gains, or losses with respect to his or her Matching Contribution Sub-Account and Deferred Compensation Sub-Account calculated based on the deemed investment alternatives below, in increments of 1%. In the event the Participant fails to make an election regarding the deemed investment of his or her Matching Contribution Sub-Account and Deferred Compensation Sub-Account, the Participant shall be deemed to have elected to invest 100% of his or her Matching Contribution Sub-Account and Deferred Compensation Sub-Account in the Money Market Fund within Investment Option (as described below). The Participant’s investment election shall continue in effect unless and until modified by the Participant. Any such modification shall apply prospectively and may apply to amounts previously deferred under the Deferred Compensation Program (and related earnings).

(b) Common Stock Option. Any portion of the Matching Contribution Sub-Account and Deferred Compensation Sub-Account deemed invested under this option (the “Common Stock Option”) shall be accounted for as if invested in shares of Common Stock purchased at Fair Market Value on the date on which a Deferral Contribution is credited to the Participant’s Account. The Participant’s Matching

Contribution Sub-Account and Deferred Compensation Sub-Account shall be credited on a quarterly basis with an amount equal to the dividends that would have become payable during the deferral period if actual purchases of Common Stock had been made, with such dividends accounted for as if invested in Common Stock as of the payable date for such dividends. Any credited shares treated as if they were purchased with dividends shall be deemed to have been purchased at Fair Market Value on the dividend payment date. The Committee may prescribe such limitations as it deems advisable in its sole discretion on a Participant's deemed investment in the Common Stock Option.

(c) Investment Options. Any portion of the Matching Contribution Sub-Account and Deferred Compensation Sub-Account deemed invested under this option (the "Investment Option") shall be deemed invested in one or more of the investment options made available from time to time for Participants under the Plan. Each such deemed investment shall be credited or debited with earnings or losses as if the amount invested had been invested in the applicable investment fund made available by the Committee.

ARTICLE 6
DISTRIBUTIONS

All distributions of a Participant's Account under the Deferred Compensation Program shall be made in accordance with the Participant's election(s) (or deemed election(s)) under Articles 4 and 6 of the Wrap Plan.

Exhibit B

401(k) SUPPLEMENTAL PROGRAM

a component Program of the
QEP Resources, Inc. Deferred Compensation Wrap Plan

QEP RESOURCES, INC.
401(k) SUPPLEMENTAL PROGRAM

ARTICLE 1
INTRODUCTION

1.1 Establishment of Program. The Company hereby establishes this revised 401(k) Supplemental Program under the Wrap Plan, as of January 1, 2012. Unless otherwise defined herein, all capitalized terms herein shall the meanings set forth in the QEP Resources, Inc. Deferred Compensation Wrap Plan.

1.2 Purpose. The purpose of the 401(k) Supplemental Program is to provide a benefit to a Participant approximately equal to the benefit that the Participant would have received under the Investment Plan if the Compensation Limit were inapplicable.

ARTICLE 2
PARTICIPATION; ELECTIONS

2.1 Participation. An Employee shall be an Eligible Employee for purposes of this Program if he or she is in a salary classification designated by the Committee as eligible to participate in the Program for a Plan Year or is otherwise designated as an Eligible Employee by the Committee and will receive Compensation in excess of a threshold established by the Committee. An Employee shall begin participation in the 401(k) Supplemental Program on the date in any Plan Year that the Employee first receives Compensation in excess of the Compensation Limit or on a date in any Plan Year as otherwise determined by the Compensation Committee.

2.2 Elections. Each Participant shall make elections with regard to the deferral of Compensation and the time and form of payments under the 401(k) Supplemental Program in accordance with Articles 4 and 6 of the Wrap Plan.

ARTICLE 3
DEFERRAL CONTRIBUTIONS

Each Plan Year, a Participant electing to defer Compensation under the 401(k) Supplemental Program must defer a percentage of his or her compensation equal to the company matching contributions as determined for the Investment Plan commencing on the date the Participant is deemed eligible to begin participation in the Program.

ARTICLE 4
MATCHING CONTRIBUTIONS

4.1 Amount of Matching Contributions. A Participant who makes Deferral Contributions to the 401(k) Supplemental Program for a Plan Year shall be entitled to a Matching Contribution for such Plan Year in an amount equal to the amount deferred by the Participant.

4.2 Vesting. A Participant shall be fully vested at all times in the portion of his or her Account attributable to Deferral Contributions and shall be vested in the portion of his or her Account attributable to Matching Contributions to the same extent as such Participant is vested in any matching contributions under the Investment Plan.

ARTICLE 5
ACCOUNTS; DEEMED INVESTMENTS

5.1 Accounts. The Committee shall establish an Account and sub-accounts for each Participant as are necessary for the proper administration of the 401(k) Supplemental Program. Such Accounts shall reflect Deferral Contributions and Matching Contributions made by or on behalf of the Participant, together with any adjustments for income, gain or loss and any payments from the Account as provided herein. Deferral Contributions and related Matching Contributions shall be credited to the Participant's Account as soon as administratively practicable after the Deferral Contribution would have otherwise been paid to the Participant.

5.2 Status of Accounts. Accounts and sub-accounts established hereunder shall be record-keeping devices utilized for the sole purpose of determining benefits payable under the 401(k) Supplemental Program, and will not constitute a separate fund of assets but shall continue for all purposes to be part of the general, unrestricted assets of the Employer, subject to the claims of its general creditors.

5.3 Deemed Investment of Accounts in 401(k) Supplemental Program.

(a) 401(k) Supplemental Program. In connection with his or her enrollment in the 401(k) Supplemental Program, a Participant may elect to have earnings, gains, or losses with respect to his or her Matching Contributions and Deferral Contributions Accounts calculated based on the deemed investment alternatives below, in increments of 1%. In the event the Participant fails to make an election regarding the deemed investment of his or her Matching Contributions and Deferral Contributions, the Participant shall be deemed to have elected to invest 100% of his or her Matching Contributions and Deferral Contributions in the Money Market Fund within Investment Option (as described below). The Participant's investment election shall continue in effect unless and until modified by the Participant. Any such modification shall apply prospectively and may apply to amounts previously deferred under the 401(k) Supplemental Program (and related earnings).

(b) Common Stock Option. Any portion of the Matching Contributions Account and Deferral Contributions Account deemed invested under this option (the "Common Stock Option") shall be accounted for as if invested in shares of Common Stock purchased at Fair Market Value on the date on which a Matching Contribution or a Deferral Contribution is credited to the Participant's Account. The Participant's Matching Contributions Account and Deferral Contributions Account shall be credited on a quarterly basis with an amount equal to the dividends that would have become payable during the deferral period if actual purchases of Common Stock had been made, with such dividends accounted for as if invested in Common Stock as of the payable date for such dividends. Any credited shares treated as if they were purchased with dividends shall be deemed to have been purchased at Fair Market Value on the dividend payment date. The Committee may prescribe such limitations as it deems advisable in its sole discretion on a Participant's deemed investment in the Common Stock Option.

(c) Investment Plan Options. Any portion of the Matching Contributions Account or Deferral Contributions Account deemed invested under this option (the "Investment Plan Option") shall be deemed invested in one or more of the investment options made available from time to time for Participants under the Plan. Each such deemed investment shall be credited or debited with earnings or losses as if the amount invested had been invested in the underlying fund in the Investment Plan.

ARTICLE 6
DISTRIBUTIONS

All distributions of a Participant's Account under the 401(k) Supplemental Program shall be made in accordance with the Participant's election(s) (or deemed election(s)) under Articles 4 and 6 of the Wrap Plan.

Exhibit 10.10

QEP RESOURCES, INC.

DEFERRED COMPENSATION PLAN FOR DIRECTORS

QEP RESOURCES, INC.
DEFERRED COMPENSATION PLAN FOR DIRECTORS

ARTICLE 1
INTRODUCTION

1.1 Purpose. QEP Resources, Inc., a Delaware corporation (the "Company"), hereby establishes this QEP Resources, Inc. Deferred Compensation Plan for Directors (the "Plan") to provide Directors (as defined below) of the Company and its participating Affiliates (as defined below) with an opportunity to defer compensation paid to them for their services as Directors and to maintain a deferred compensation account until they cease to serve as Directors of the Company and its Affiliates.

1.2 Status of Plan. This Plan is intended to be an unfunded, nonqualified deferred compensation arrangement designed to comply with Section 409A of the Internal Revenue Code of 1986, as amended, and the regulations and guidance promulgated thereunder. Notwithstanding any other provision herein, this Plan shall be interpreted, operated and administered in a manner consistent with these intentions.

ARTICLE 2
DEFINITIONS

For purposes of the Plan, the following terms or phrases shall have the following indicated meanings, unless the context clearly requires otherwise:

2.1 "Account" or "Account Balance" means, for each Participant, the account established for his or her benefit under the Plan, which records the credit on the records of the Company and its Affiliates equal to the amounts set aside under the Plan and the actual or deemed earnings, if any, credited to such account. The Account Balance, and each other specified account or sub-account, shall be a bookkeeping entry only and shall be used solely as a device for the measurement and determination of the amounts to be paid to a Participant, or his or her designated Beneficiary, pursuant to this Plan.

2.2 "Affiliate" means any entity that is treated as the same employer as the Company under Sections 414(b), (c), (m), or (o) of the Code (defined below), any entity required to be aggregated with the Company pursuant to regulations adopted under Code Section 409A, or any entity otherwise designated as an Affiliate by the Company.

2.3 "Beneficiary" means that person or persons who become entitled to receive a distribution of benefits under the Plan in the event of the death of a Participant prior to the distribution of all benefits to which he or she is entitled.

2.4 "Board" means the Board of Directors of the Company.

2.5 "Cash Compensation" means compensation payable to a Director in cash for serving as a Director, including attending Board and committee meetings as a Director, during a Plan Year, but excluding any expense reimbursements.

2.6 "Change in Control" shall be deemed to have occurred if: (i) any individual, entity, or group (within the meaning of Section 13(d)(3) or 14(d)(2) of the Securities Exchange Act of 1934 (the "Exchange Act")) other than a trustee or other fiduciary holding securities under an employee benefit plan of the Company, is or becomes the beneficial owner (as such term is used in Rule 13d-3 under the Exchange Act) of securities of the Company representing 30 percent or more of the combined voting power of the Company; or (ii) the following individuals cease for any reason to constitute a majority of the number of directors then serving: individuals who, as of the Effective Date, constitute the Company's Board of Directors and any new director (other than a director whose initial assumption of office is in connection with an actual or threatened election contest, including but not limited to a consent solicitation, relating to the election of directors of the Company) whose appointment or election by the Board or nomination for election by the Company's stockholders was approved or recommended by a vote of at least two-thirds of the directors then still in office who either were directors on the Effective Date, or whose appointment, election or nomination for election was previously so approved or recommended; or (iii) the consummation of a merger or consolidation of the Company or any direct or indirect subsidiary of the Company with any corporation, other than a merger or consolidation that would result in the voting securities of the Company outstanding immediately prior to such merger or consolidation continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity or any parent thereof) at least 60 percent of the combined voting power of the securities of the Company or such surviving entity or its parent outstanding immediately after such merger or consolidation, or a merger or consolidation effected to implement a recapitalization of the Company (or similar transaction) in which no person is or becomes the beneficial owner, directly or indirectly, of securities of the Company representing 30 percent or more of the combined voting power of the Company's then outstanding securities; or (iv) the Company's stockholders approve a plan of complete liquidation or dissolution of the Company or there is consummated for the sale or disposition by the Company of all or substantially all of the Company's assets, other than a sale or disposition by the Company of all or substantially all of the Company's assets to an entity, at least 60 percent of the combined voting power of the voting securities of which are owned by the stockholders of the Company in substantially the same proportions as their ownership of the Company immediately prior to such sale. In addition, if a Change in Control constitutes a payment event with respect to any payment under the Plan which provides for the deferral of compensation and is subject to Section 409A of the Code, the transaction or event described in clauses (i), (ii), (iii) and (iv) with respect to such payment must also constitute a "change in control event," as defined in Treasury Regulation Section 1.409A-3(i)(5) to the extent required by Section 409A of the Code.

2.7 "Code" means the Internal Revenue Code of 1986, as amended.

2.8 "Common Stock" means the no par value common stock of the Company.

2.9 "Common Stock Option" means the investment option available under Section 5.3(b)(i) with respect to a Participant's election to defer cash compensation that is deemed to invest in Common Stock as set forth therein.

2.10 "Company" means QEP Resources, Inc., a corporation organized and existing under the laws of the State of Delaware, or its successor or successors.

2.11 "Company Equity Plan" means the QEP Resources Inc. 2010 Long-Term Stock Incentive Plan, as it may be amended or restated from time to time, or, to the extent applicable, any future or successor equity compensation plan of the Company.

2.12 "Disability" means a condition that renders a Participant unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment which can be expected to result in death or can be expected to last for a continuous period of not less than 12 months, as described in Treas. Reg. Section 1.409A-3(i)(4)(i)(A). A Participant shall not be considered to be disabled unless the

Participant furnishes proof of the existence of such disability in such form and manner as may be required by regulations promulgated under, or applicable to, Code Section 409A.

2.13 "Director" means a member of the Board or the Board of Directors of any participating Affiliate who is not an employee (as defined in accordance with Section 3401(c) of the Code and the regulations and revenue rulings thereunder) of the Company or any of its Affiliates.

2.14 "Fair Market Value" means the closing benchmark price of the Company's Common Stock as reported on the composite tape of the New York Stock Exchange for any given valuation date, or if the Common Stock shall not have been traded on such date, the closing price on the next preceding day on which a sale occurred.

2.15 "Participant" means any Director who has commenced participation in the Plan in accordance with Article 3.

2.16 "Phantom Stock" means an economic unit equal in value to one share of Common Stock, which is issued to a Director as compensation for services performed as a Director pursuant to this Plan and the QEP Resources, Inc. 2010 Long-Term Stock Incentive Plan, as amended or restated from time to time, based upon his or her election to receive such Phantom Stock in lieu of Restricted Stock pursuant to this Plan.

2.17 "Phantom Stock Agreement" means an agreement that may be entered into between the Company and a Director containing terms and conditions applicable to Phantom Stock allocated to the Director under the Plan. A Phantom Stock Agreement will be entered into with Directors under the Plan only if and to the extent determined by the Board.

2.18 "Plan" means this QEP Resources, Inc. Deferred Compensation Plan for Directors, as amended or restated from time to time.

2.19 "Plan Year" means the calendar year.

2.20 "Restricted Stock" means the restricted shares of Common Stock of the Company issued to a Director as compensation for services performed as a Director.

2.21 "Separation from Service" means a "separation from service" within the meaning of Section 409A(a)(2)(A)(i) of the Code and Treasury Regulation Section 1.409A-1(h).

2.22 "Unforeseeable Emergency" shall mean a severe financial hardship of the Participant resulting from: (i) an illness or accident of the Participant, the Participant's spouse, the Participant's Beneficiary, or the Participant's dependent (as defined in Code Section 152, without regard to Code Section 152(b)(1), (b)(2) and (d)(1)(B)); (ii) a loss of the Participant's property due to casualty; or (iii) such other similar extraordinary and unforeseeable circumstances arising as a result of events beyond the control of the Participant, as described in Treas. Reg. Section 1.409A-3(i)(3)(i), in each case as determined in the sole discretion of the Board.

ARTICLE 3
ELIGIBILITY; PARTICIPATION

3.1 Eligibility. Any Director who is entitled to receive compensation for service as a Director shall be eligible to participate in the Plan as of the first date the individual becomes a Director.

3.2 Enrollment and Commencement of Deferrals. Each eligible Director who wishes to participate in the Plan for a Plan Year must make an irrevocable election as to the deferral of Cash Compensation and/or the receipt of Phantom Stock in lieu of Restricted Stock for the Plan Year by timely completing, executing and returning to the Company's Human Resources department such election forms or other enrollment materials as the Board requires as follows:

(a) in the case of a Director who first becomes eligible to participate in the Plan as of the first day of a Plan Year, on or prior to December 31st of the prior Plan Year; and

(b) in the case of a Director who first becomes eligible to participate in the Plan after the first day of a Plan Year, within thirty (30) days after the date the Director first becomes eligible to participate.

If a Director fails to timely complete such election forms or other enrollment materials, the Director shall not participate in the Plan until the first day of the first Plan Year beginning after the date on which the Director timely completes, executes and returns such election forms or other enrollment materials to the Company's Corporate Secretary.

3.3 Failure of Eligibility. If the Board determines, in its sole and absolute discretion, that any Participant no longer meets the eligibility criteria of the Plan, the Participant shall cease to be an active Participant in the Plan and future contributions to the Plan made by or on behalf of the Participant shall cease as of the date of such determination by the Board. The Board's determination hereunder shall be final and binding on all persons.

ARTICLE 4
ELECTIONS; AMOUNTS; MODIFICATIONS

4.1 First Year of Plan Participation. In connection with a Participant's enrollment in the Plan pursuant to Section 3.2, the Participant shall make an irrevocable election for the Plan Year in which the Participant commences participation (i) to defer (or not to defer) all, but not less than all, of his or her Cash Compensation, and/or (ii) to receive (or not to receive) Phantom Stock in lieu of the grant of Restricted Stock that the Participant would otherwise have received during such Plan Year. The Participant's initial deferral election under this Section 4.1 shall apply solely to compensation to be paid with respect to services performed on or after the date of the Participant's enrollment in the Plan, and shall continue to apply for all succeeding Plan Years unless and until revoked or modified pursuant to Section 4.2, below. If the Participant fails to timely complete, execute and return such election forms or other enrollment materials as required by the Board in accordance with Section 3.2, then the Participant shall not be permitted to make to defer any Cash Compensation or receive any Phantom Stock under the Plan for such Plan Year.

In connection with a Participant's enrollment in the Plan pursuant to Section 3.2, the Participant shall also make an irrevocable election for the Plan Year as to the form of distribution (from the options available under Section 6.1 (b) below) of any deferrals (in the form of Cash Compensation and/or Phantom Stock) credited to his or her Account for such Plan Year (including earnings thereon). If the Participant fails to make such election, or if such election does not meet the requirements of Code Section 409A and related Treasury guidance or regulations, the Participant shall be deemed to have elected to receive a lump sum distribution. The Participant's election (or deemed election) shall continue to apply for succeeding Plan Years unless and until the election is modified pursuant to Section 4.2, below. Any such modification shall apply prospectively only and shall not apply to deferrals (in the form of Cash Compensation and/or Phantom Stock) previously credited under the Plan (or any earnings thereon).

4.2 Subsequent Plan Years. For each succeeding Plan Year, the Participant may, prior to December 31st of the immediately preceding Plan Year (or such earlier deadline as is established by the Board in its sole discretion):

(i) make an irrevocable election to modify or revoke the Participant's existing election to (i) defer (or not to defer) all, but not less than all, of his or her Cash Compensation for succeeding Plan Years, and/or (ii) receive (or not to receive) Phantom Stock in lieu of the grant of Restricted Stock that the Participant would otherwise be entitled to receive for succeeding Plan Years. Any such new election shall remain in effect for all succeeding Plan Years unless and until timely revoked or modified by the Participant in accordance with this Section. Any such modification shall apply prospectively only and shall not apply to Cash Compensation previously credited under the Plan (or any earnings thereon) or Phantom Stock previously received in lieu of Restricted Stock.

(ii) make an irrevocable election to modify his or her existing election as to the form of distribution of any deferrals (in the form of Cash Compensation and/or Phantom Stock) credited to his or her Account for succeeding Plan Years (including earnings thereon). Such election shall be made in accordance with Section 6.1 (b) below, and shall remain in effect for all succeeding Plan Years unless and until timely modified by the Participant in accordance with this Section. Any such modification shall apply prospectively only and shall not apply to Cash Compensation previously credited under the Plan (or any earnings thereon) or Phantom Stock previously received in lieu of Restricted Stock.

ARTICLE 5
ACCOUNTS; DEEMED INVESTMENTS

5.1 Accounts. The Company shall establish an Account for each Participant with at least two sub-accounts - an Equity Compensation Sub-Account and a Cash Compensation Sub-Account - along with such additional sub-accounts as it deems necessary or desirable for the proper administration of the Plan. The Equity Compensation Sub-Account shall reflect the value of Phantom Stock issued to the Participant in lieu of Restricted Stock for each Plan Year, together with any adjustments for income, gain or loss and any payments from such sub-account as provided herein. Phantom Stock shall be credited to the Participant's Equity Compensation Sub-Account and relevant sub-accounts (if any) as of the date the Restricted Stock would otherwise have been granted to the Participant if the Participant had not elected to defer such amounts under this Plan, subject to Section 5.3(a). The Cash Compensation Sub-Account shall reflect all deferrals of Cash Compensation made by the Participant for each Plan Year, together with any adjustments for income, gain or loss and any payments from such sub-account as provided herein. Cash Compensation deferred by a Participant under this Plan shall be credited to the Participant's Cash Compensation Account and relevant sub-accounts (if any) as soon as administratively practicable after the amounts would have otherwise been paid to the Participant.

5.2 Status of Accounts. Accounts and sub-accounts established hereunder shall be record-keeping devices utilized for the sole purpose of determining benefits payable under this Plan, and will not constitute a separate fund of assets but shall continue for all purposes to be part of the general, unrestricted assets of the Company and its Affiliates, subject to the claims of their general creditors.

5.3 Deemed Investment of Amounts Deferred.

(a) Equity Compensation Sub-Account. The Participant's Equity Compensation Sub-Account shall hold shares of the Participant's Phantom Stock and shall be credited with earnings and dividends as set forth in this Section 5.3(a).

(i) Earnings and Dividends. All shares of Phantom Stock deemed held in the Participant's Equity Compensation Sub-Account shall be credited on a quarterly basis with an amount equal to the dividends that would have become payable during the deferral period if actual purchases of Common Stock had been made, with such dividends accounted for as if invested in additional shares of Phantom Stock as of the payable date for such dividends. Any credited shares treated as if they were purchased with dividends shall be deemed to have been purchased at Fair Market Value on the dividend payment date.

(ii) Vesting. Unless otherwise provided under the terms of a Phantom Stock Agreement and subject to subsection (i) above, in the event a Participant elects to defer under this Plan any award of Restricted Stock that, in accordance with the director compensation program or policy then in effect, would have been subject to vesting or other forfeiture restrictions, then the corresponding Phantom Stock under this Plan and any earnings and dividends attributable thereto shall be subject to the same vesting and forfeiture restrictions as would have otherwise applied to such Restricted Stock and/or the earnings and dividends thereon, as applicable. In the event the Participant forfeits shares of Phantom Stock in accordance with the foregoing or the terms of a Phantom Stock Agreement, the Participant's Equity Compensation Sub-Account shall be debited for the number of shares of Phantom Stock forfeited along with any earnings and dividends related to such shares.

(b) Cash Compensation Sub-Account. In connection with a Participant's election to defer compensation for a Plan Year pursuant to Article 4, a Participant may elect to have earnings, gains, or losses with respect to deferrals into his or her Cash Compensation Sub-Account for such Plan Year calculated based on either the Common Stock Option or the Investment Option. The Participant's actual or deemed investment election shall continue in effect for future Plan Years unless and until modified by the Participant. Any such modification (i) shall apply prospectively only to amounts deferred in future Plan Years, and (ii) shall be made at the same time as modifications to deferral elections are made under Section 4.2 above.

(i) Common Stock Option. Any portion of the Cash Compensation Sub-Account deemed invested under this option (the "Common Stock Option") shall be accounted for as if invested in shares of Common Stock purchased at Fair Market Value on the date on which a deferral of Cash Compensation is credited to the Participant's Account. All shares of Common Stock deemed held in the Participant's Cash Compensation Sub-Account shall be credited on a quarterly basis with an amount equal to the dividends that would have become payable during the deferral period if actual purchases of Common Stock had been made, with such dividends accounted for as if invested in Common Stock as of the payable date for such dividends. Any credited shares treated as if they were purchased with dividends shall be deemed to have been purchased at Fair Market Value on the dividend payment date.

(ii) Investment Option. Any portion of the Cash Compensation Sub-Account deemed invested under this option (the "Investment Option") shall be deemed invested in one or more of the investment options made available from time to time for Participants under the Plan. Each such deemed investment shall be credited or debited with earnings or losses as if the amount invested had been invested in the applicable investment fund made available by the Board.

ARTICLE 6
DISTRIBUTIONS

6.1 Permissible Times and Forms of Payments. Subject to Article 7, below, A Participant may elect to receive his or her Account pursuant to an election form filed in accordance with Article 4 at the following times and in the following forms:

(a) Time of Distribution. A Participant may elect to receive a distribution as of the date of, or at a designated anniversary date following, the first to occur of the Participant's Separation from Service or Disability or at a designated time or times specified by the Participant in his or her election forms, which shall not be earlier than 24 months from the date of deferral of the amount to be distributed.

(b) Form of Distribution. A Participant may elect to receive a distribution of his or her Account in any of the following forms:

(i) a single lump sum;
(ii) up to ten (10) annual installments; or
(iii) in the case of an in-service distribution a single lump sum of the entire Account Balance made in one or more Plan Years, as designated by the Participant.

(c) Subsequent Deferrals. Notwithstanding an actual or deemed election as to the timing of the distribution of a Participant's Account, at such times and in such manner as the Board may determine, a Participant may make an irrevocable election to delay the payment, or the commencement of payment, of his or her Account, but only if such election (i) is made not less than 12 months before the date the payment or commencement of installment payments is scheduled to be paid or to begin; (ii) shall not take effect until at least 12 months after the date the election is made; and (iii) relating to a payment not being made on account of death, Disability or an Unforeseeable Emergency, delays the payment or commencement of payments for a period of at least five years from the date the payment or series of payments was scheduled to be paid or begin.

6.2 Change in Control. Notwithstanding any election made by the Participant, in the event of a Change in Control, all amounts then credited to the Participant's Account shall be distributed to the Participant in a single lump sum within 60 days following the Change in Control.

6.3 Calculation of Distributions.

(a) Lump Sum. All cash lump sum distributions shall be based on the value of the Participant's Account (or the portion thereof to be paid in a lump sum) as of the closest administratively feasible valuation date preceding the date distribution is made, in accordance with rules established by the Board.

(b) Installment Distributions. Under an installment payout, the amount to be distributed in each installment payment shall be determined by dividing the value of the Participant's Accounts being paid in installments as of the closest administratively feasible valuation date preceding the date of each distribution by the number of installment payments remaining to be made, in accordance with rules established by the Board. In the event of the death of the Participant prior to the full payment of his Accounts being paid in installments, payments will continue to be made to his Beneficiary in the same manner as would have been payable to the Participant.

6.4 Method of Payment. All payments under the Plan shall be made in cash, provided, however, that, solely with respect to amounts in a Participant's Cash Compensation Sub-Account that are deemed invested in shares of Common Stock and amounts in a Participant's Equity Compensation Sub Account, if prior to distribution and in accordance with administrative procedures and notice requirements that may be established by the Company from time to time, a Participant timely requests that a payment be made in the form of Common Stock (a "Stock Distribution Request"), then, unless otherwise determined by the Board in its sole discretion, such amounts shall be paid in the form of an equal number of actual shares of Common Stock , which shares of Common Stock shall be delivered to the Participant under the Company Equity Plan as of the date the distribution is made. For the avoidance of doubt, the Company shall have the right to pay all amounts under the Plan in cash notwithstanding any Equity Distribution Request, as determined by the Board in its discretion.

ARTICLE 7
WITHDRAWALS FOR UNFORESEEABLE EMERGENCIES

7.1 Petition. If the Participant experiences an Unforeseeable Emergency, the Participant may petition the Board in writing to receive a partial or full payout from the Plan, subject to the provisions set forth below. A Participant's written petition for such a payment shall describe the circumstances which the Participant believes justify the payment and an estimate of the amount necessary to eliminate the Unforeseeable Emergency.

7.2 Amount of Withdrawal; Necessity. The payout, if any, from the Plan shall not exceed the lesser of: (i) the Participant's vested Account Balance, calculated as of the close of business on or around the date on which the amount becomes payable, as determined by the Board in its sole discretion; or (ii) the amount necessary to satisfy the Unforeseeable Emergency, plus amounts necessary to pay Federal, state, or local income taxes or penalties reasonably anticipated as a result of the distribution. Notwithstanding the foregoing, a Participant may not receive a payout from the Plan to the extent that the Unforeseeable Emergency is or may be relieved (a) through reimbursement or compensation by insurance or otherwise, (b) by liquidation of the Participant's assets, to the extent the liquidation of such assets would not itself cause severe financial hardship, or (c) by cessation of deferrals under this Plan.

7.3 Payment; Cessation of Deferrals. If the Board, in its sole discretion, approves a Participant's petition for payout from the Plan, the Participant shall receive a payout in the form of a lump sum from the Plan within sixty (60) days of the date of such approval, and the Participant's deferrals of Cash Compensation then in effect under the Plan shall be terminated as of the date of such approval.

7.4 409A. Any payment as a result of an Unforeseeable Emergency shall be made in accordance with Code Section 409A(a)(2)(A)(vi) and the regulations thereunder.

ARTICLE 8
ACCOUNT STATEMENTS

Within 60 days after the end of the calendar year, a statement will be sent to each Participant listing the balance in his or her Account as of the last day of the Plan Year.

ARTICLE 9
ADMINISTRATION

The Board shall administer the Plan and shall have full authority to make such rules and regulations deemed necessary or desirable to administer the Plan and to interpret its provisions. However, no member of the Board shall vote or act on any matter relating solely to himself or herself.

9.1 Board to Administer and Interpret Plan. The Board or its designee shall administer the Plan and shall have all discretion and power necessary for that purpose. The Board shall have the discretion, authority, and power to (i) make, amend, interpret, and enforce all appropriate rules and regulations for the administration of the Plan and (ii) decide or resolve any and all questions that may arise in connection with this Plan, including interpretations of the Plan and determinations of eligibility to participate and to receive distributions under the Plan. Any individual serving on the Board, or anyone delegated responsibilities by the Board, shall not vote or act on any matter relating solely to himself. When making a determination or calculation, the Board shall be entitled to rely on information supplied by a Participant, Beneficiary, or the Employer, as the case may be. The Board shall maintain all records of the Plan.

9.2 Agents. In the administration of this Plan, the Board may, from time to time, employ agents (including officers and other employees of the Company) and delegate to them such administrative duties as it sees fit (including acting through a duly appointed representative) and may from time to time consult with counsel who may be counsel to the Company.

9.3 Binding Effect of Decisions. The decision or action of the Board with respect to any question arising out of or in connection with the administration, interpretation and application of the Plan and the rules and regulations promulgated hereunder shall be final and conclusive and binding upon all persons having any interest in the Plan.

9.4 Indemnity of Board. The Company shall indemnify and hold harmless the members of the Board and any employee to whom duties of the Board may be delegated against any and all claims, losses, damages, expenses or liabilities arising from any action or failure to act with respect to this Plan, except in the case of willful misconduct by the Board, any of its members, or any such employee.

9.5 Agent for Legal Process. The Board shall be agent of the Plan for service of all legal process.

ARTICLE 10
AMENDMENT AND TERMINATION

The Plan may be amended, modified or terminated by the Board. No amendment, modification, or termination shall adversely affect a Participant’s rights with respect to amounts vested in his or her Account.

ARTICLE 11
MISCELLANEOUS

11.1 Election Forms. All elections shall be made on forms prepared by the Corporate Secretary and must be dated, signed, and filed with the Company’s Human Resources department in order to be valid.

11.2 Source of Payments. The Company and each participating Affiliate will pay all benefits for its Directors arising under this Plan, and all costs, charges and expenses relating to such benefits, out of its general assets. The right of a Participant to receive any unpaid portion of his or her Account shall be an unsecured claim against the general assets of the Company and its Affiliates and will be subordinated to the general obligations of the Company and its Affiliates.

11.3 No Assignment or Alienation.

(a) General. Except as provided in subsection (b) below, the benefits provided for in this Plan shall not be anticipated, assigned (either at law or in equity), alienated, or be subject to attachment, garnishment, levy, execution or other legal or equitable process. Any attempt by any Participant or any Beneficiary to anticipate, assign or alienate any portion of the benefits provided for in this Plan shall be null and void.

(b) Exception: DRO. The restrictions of subsection (a) shall not apply to a distribution to an "alternate payee" (as defined in Code Section 414(p)) pursuant to a "domestic relations order" ("DRO") within the meaning of Code Section 414(p)(1)(B). The Board shall have the discretion, power, and authority to determine whether an order is a DRO. Upon a determination that an order is a DRO, the Board shall cause the Company or the relevant Affiliate to make a distribution to the alternate payee or payees named in the DRO, as directed by the DRO.

11.4 Beneficiaries. A Participant shall have the right, in accordance with forms and procedures established by the Board, to designate one or more Beneficiaries to receive some or all amounts payable under the Plan after the Participant's death. In the absence of an effective Beneficiary designation, all payments shall be made to the personal representative of the Participant's estate.

11.5 No Creation of Rights. Nothing in this Plan shall confer upon any Participant the right to continue as a Director. The right of a Participant to receive a distribution shall be an unsecured claim against the general assets of the Company. Nothing contained in this Plan or its component Programs nor any action taken hereunder shall create, or be construed to create, a trust of any kind, or a fiduciary relationship between the Company and the Participants, Beneficiaries, or any other persons. All Accounts under the Plan and its component Programs shall be maintained for bookkeeping purposes only and shall not represent a claim against specific assets of any Company.

11.6 Payments to Incompetents. If the Board determines in its discretion that a benefit under this Plan is to be paid to a minor, a person declared incompetent or to a person incapable of handling the disposition of his or her property, the Board may direct payment of such benefit to the guardian, legal representative or person having the care and custody of such minor, incompetent or incapable person. The Board may require proof of minority, incompetence, incapacity or guardianship, as it may deem appropriate prior to distribution of the benefit. Any such payment shall be a payment for the account of the Participant and the Participant's Beneficiary, as the case may be, and shall be a complete discharge of any liability under the Plan for such payment amount.

11.7 Court Order. The Board is authorized to make any payments directed by court order in any action in which the Plan or the Board has been named as a party.

11.8 Code Section 409A Savings Clause. The payments and benefits provided under the Plan are intended to be compliant with the requirements of Section 409A of the Code. Notwithstanding any provision of this Plan to the contrary, including, without limitation, Article 10 hereof, in the event that the Company reasonably determines that any payments or benefits hereunder are not either exempt from or compliant with the requirements of Section 409A of the Code, the Company shall have the right adopt such amendments to this Plan or adopt such other policies and procedures (including amendments, policies and procedures with retroactive effect), or take any other actions, that are necessary or appropriate (i) to preserve the intended tax treatment of the payments and benefits provided hereunder, to preserve the economic benefits with respect to such payments and benefits, and/or (ii) to exempt such payments and benefits from Section 409A of the Code or to comply with the requirements of Section 409A of the Code and thereby avoid the application of penalty taxes thereunder; provided, however, that this Section 11.8 does not, and shall not be construed so as to, create any obligation on the part of the Company to adopt any such amendments, policies or procedures or to take any other such actions or to indemnify any Participant for any failure to do so.

11.9 Attorney Fees; Interest. The Company and its Affiliates agrees to pay as incurred, to the full extent permitted by law, and in accordance with Code Section 409A, all legal fees and expenses which a Participant may reasonably incur as a result of any contest (regardless of the outcome thereof) by the Company, the Participant, or others following a Change in Control regarding the validity or enforceability of, or liability under, any provision of this Plan or any guarantee of performance thereof (including as a result of any contest by the Participant about the amount of any payment pursuant to this Plan), plus in each case interest on any delayed payment at the applicable Federal rate provided for in Section 7872(f)(2)(A) of the Code. The foregoing right to legal fees and expenses shall not apply to any contest brought by a Participant (or other party seeking payment under the Plan) that is found by a court of competent jurisdiction to be frivolous or vexatious. To the extent that any payments or reimbursements provided to the Participant under this Section are deemed to constitute compensation to the Participant, such amounts shall be paid or reimbursed reasonably promptly, but not later than December 31 of the year following the year in which the expense was incurred. The amount of any payments or expense reimbursements that constitute compensation in one year shall not affect the amount of payments or expense reimbursements constituting compensation that are eligible for payment or reimbursement in any subsequent year, and the Participant's right to such payments or reimbursement of any such expenses shall not be subject to liquidation or exchange for any other benefit.

11.10 Distribution in the Event of Taxation. If, for any reason, all or any portion of a Participant's benefits under this Plan becomes subject to federal income tax under Code Section 409A with respect to the Participant prior to receipt, a Participant may petition the Board for a distribution of that portion of his or her benefit that has become taxable. Upon the grant of such a petition, which grant shall not be unreasonably withheld, the Company or the relevant Affiliate shall distribute to the Participant immediately available funds in an amount equal to the taxable portion of his or her benefit (which amount shall not exceed a Participant's unpaid vested Account balances). If the petition is granted, the tax liability distribution shall be made within 90 days of the date when the Participant's petition is granted. Such a distribution shall affect and reduce the benefits to be paid under this Plan.

11.11 Governing Law. To the extent not preempted by federal law, this Plan shall be governed by the laws of the State of Colorado, without regard to conflicts of law principles.

[*Signature Page Follows*]

I hereby certify that this QEP Resources, Inc. Deferred Compensation Plan for Directors was duly amended by the Board of Directors of QEP Resources, Inc. on ____________ __, 201_.

Executed on this 23 day of February, 2015.

By: /s/ Richard J. Doleshek

Richard J. Doleshek
Executive Vice President and Chief Financial Officer

QEP RESOURCES, INC.
CASH INCENTIVE PLAN

PERFORMANCE SHARE UNIT AWARD AGREEMENT

THIS PERFORMANCE SHARE UNIT AWARD AGREEMENT (the “Agreement”) is made as of this __ day of _______________, (the “Effective Date”), between QEP Resources, Inc., a Delaware corporation (the “Company”), and ______________ (the “Grantee”).

1. Grant of Performance Share Units. Subject to the terms and conditions of this Agreement and the Company’s Cash Incentive Plan (the “Plan”), the Company hereby issues to Grantee the right to receive a number of Performance Share Units calculated in the manner set forth in Appendix A hereto, based on the achievement of one or more Performance Goals that must be attained over a relevant Performance Period, and assuming a target award of ______________ Performance Share Units (the “Target Share Units”). Each Performance Share Unit actually earned and vested in accordance with this Agreement and Appendix A hereto represents the right to receive a cash payment equal to the Fair Market Value of one share of the Company’s no par value common stock (“Common Stock”), on the terms and subject to the conditions of this Agreement. Terms not defined herein shall have the meanings ascribed to them in the Plan.

2. Vesting; Termination of Employment; Forfeiture.
General. Except as set forth below, the Grantee will vest and become entitled to any Performance Share Units earned in accordance with this Agreement and Appendix A hereto only if (i) Grantee remains in the continuous employment of the Company and its Affiliates from the Effective Date through the last day of the Performance Period and (ii) the Compensation Committee (the “Committee”) certifies the award calculation and payout.

   a) Termination of Employment**.** If the Grantee terminates employment with the Company and its Affiliates for any reason other than death, Disability, or Retirement prior to the last day of the Performance Period, the Grantee shall forfeit any and all interest under this Agreement and shall forfeit the right to receive any Performance Share Units hereunder.

   b) Death, Disability, or Retirement. If the Grantee terminates employment with the Company and its Affiliates on account of death, Disability, or Retirement (as defined below) prior to the last day of the Performance Period, the Grantee shall receive a *pro rata* portion of the Performance Share Units that would otherwise have been received for the Performance Period, subject to certification by the Committee, in an amount equal to the product of (x) the number of Performance Share Units that would have been earned in accordance with the provisions of Appendix A had Grantee remained in the Continuous employment of the Company or its Affiliates through the last day of the Performance Period, *multiplied by* (y) the ratio between (i) the number of full months of employment completed from the first day of the Performance Period to the date of termination of employment and (ii) the number of full months in the Performance Period. “Retirement” shall mean Grantee’s voluntary termination of employment with the Company and its Affiliates on or after age 55 with at least 10 years of service; provided that such retirement occurs no earlier than 12 months after the first day of the Performance Period, or such other retirement as shall be approved by the Committee in its discretion.

3. Payment. As soon as practicable after the end of the Performance Period the Committee shall determine and certify the number of Performance Share Units that have been earned and vested in accordance with the Appendix A and the terms and conditions of this Agreement (the date of certification shall be the "Determination Date"). Payment for earned and vested Performance Share Units shall be made in cash. The amount distributable shall be based on the average closing Company stock price for the fourth quarter of the final year of the Performance Period. All payments shall be made as soon as administratively practicable after the Determination Date, but in all events in the calendar year following the calendar year in which the Performance Period ends.

4. Change in Control. Notwithstanding anything in this Agreement or in Appendix A to the contrary, upon the occurrence of a Change in Control (as defined in the Plan), for each of the performance periods greater than one year that is outstanding under the Plan as of the date of the Change in Control, a payment will be made in an amount equal to the actual award that would have been earned by the Participant under the Plan for such performance period, based on the level of satisfaction of the performance goals that was achieved for the performance period in which the Change in Control occurs. Solely for purposes of determining which performance periods are taken into account for purposes of the preceding sentence, (i) a performance period shall be deemed to be outstanding if payment has yet to occur for such period as of the date of the Change in Control, even if the actual performance period (i.e. the period over which performance is measured) has already ended, and (ii) a performance period shall not be deemed to be outstanding if a target award has yet to be established for such period as of the date of the Change in Control.
If the Change in Control is also a "change in control" within the meaning of Section 409A of the Internal Revenue Code (IRC), the Performance Share Units earned (if any) shall be paid on a date selected by the Committee within 30 days after the closing of the transaction that constitutes the change in control. If the Change in Control is not also a "change in control" within the meaning of Section 409A, the Company, or the successor or purchaser, as the case may be, shall make adequate provision for the assumption of the obligation to pay to the Participant such earned and vested Performance Share Units as soon as administratively practicable in the calendar year in which such amounts would otherwise have been payable to the Participant as described above.

5. No Rights of a Stockholder. The Grantee shall have no voting or other rights as a stockholder of the Company with respect to this award. The Grantee's right to receive payments earned under this Agreement shall be no greater than the right of any unsecured general creditor of the Company.

6. Adjustments to Performance Share Units. In the event of any stock dividend, extraordinary cash dividend, recapitalization, reorganization, merger, consolidation, split-up, spin-off, combination, exchange of shares, grant of warrants or rights offering to purchase Common Stock at a price materially below fair market value or other similar corporate event affecting the Common Stock, the Committee shall adjust the award issued hereunder in order to preserve the benefits or potential benefits intended to be made available under this Agreement. All adjustments shall be made in the sole and exclusive discretion of the Committee, whose determination shall be final, binding and conclusive. Notice of any adjustment shall be given to Grantee.

7. Notices. Any notice required or permitted to be given under this Agreement shall be in writing and shall be given by e-mail, hand delivery or by first class registered or certified mail, postage prepaid, addressed, if to the Company, to its Corporate Secretary, and if to Grantee, to his or her address now on file with the Company, or to such other address as either may designate in writing. Any notice shall be deemed to be duly given as of the date delivered in the case of e-mail or personal delivery,

or as of the second day after enclosed in a properly sealed envelope and deposited, postage prepaid, in a United States post office, in the case of mailed notice.

8. Amendment. Except as provided herein, this Agreement may not be amended or otherwise modified unless evidenced in writing and signed by the Company and Grantee, or as approved by the Committee.

9. Relationship to Plan. This Agreement shall not alter the terms of the Plan. If there is a conflict between the terms of the Plan and the terms of this Agreement, the terms of the Plan shall prevail. Capitalized terms used in this Agreement but not defined herein shall have the meaning given such terms in the Plan.

10. Construction; Severability. The section headings contained herein are for reference purposes only and shall not in any way affect the meaning or interpretation of this Agreement. The invalidity or unenforceability of any provision of this Agreement shall not affect the validity or enforceability of any other provision of this Agreement, and each other provision of this Agreement shall be severable and enforceable to the extent permitted by law.

11. Waiver. Any provision contained in this Agreement may be waived, either generally or in any particular instance, by the Committee appointed under the Plan, but only to the extent permitted under the Plan.

12. Entire Agreement; Binding Effect. Once accepted, this Agreement, the terms and conditions of the Plan, and the award of Restricted Stock set forth herein, constitute the entire agreement between Grantee and the Company governing such award of Restricted Stock, and shall be binding upon and inure to the benefit of the Company and to Grantee and to the Company's and Grantee's respective heirs, executors, administrators, legal representatives, successors and assigns.

13. No Rights to Employment. Nothing contained in this Agreement shall be construed as giving Grantee any right to be retained in the employ of your Employer and this Agreement is limited solely to governing the rights and obligations of Grantee with respect to the Restricted Stock.

14. Governing Law. This Agreement shall be governed by and construed in accordance with the laws of the State of Delaware, without regard to the choice of law principles thereof.

15. Section 409A.

a) The payments and benefits provided hereunder are intended to be exempt from or compliant with the requirements of Section 409A of the IRC. Notwithstanding any provision of this Agreement to the contrary, in the event that the Company reasonably determines that any payments or benefits hereunder are not either exempt from or compliant with the requirements of Section 409A of the IRC, the Company shall have the right to adopt such amendments to this Agreement or adopt such other policies and procedures (including amendments, policies and procedures with retroactive effect), or take any other actions, that are necessary or appropriate (i) to preserve the intended tax treatment of the payments and benefits provided hereunder, to preserve the economic benefits with respect to such payments and benefits, and/or (ii) to exempt such payments and benefits from Section 409A of the IRC or to comply with the requirements of Section 409A of the IRC and thereby avoid the application of penalty taxes thereunder; provided, however, that this Section does not, and shall not be construed so as to, create any obligation on the part of the Company to adopt any such amendments, policies or procedures or to take any other such actions or to indemnify Grantee for any failure to do so.

b) It is not intended that any payments to be made pursuant to this Agreement would be made on account of Grantee's "separation from service" within the meaning of Section 409A of the IRC. However, in the event that any payment is deemed to be so made, and if Grantee is a "specified employee" as defined in Section 409A on the date of such "separation from service," then notwithstanding anything to the contrary herein, no payment shall be made prior to the earliest date on which payment may be made under Section 409A(a)(2)(B)(i) (the six month delay rule for specified employees).

IN WITNESS WHEREOF, the parties have executed this Agreement as of the day and year first above written.

GRANTEE QEP RESOURCES, INC.

by__________

[Name] [NAME]

[TITLE]

APPENDIX A
TO THE PERFORMANCE SHARE UNIT AWARD AGREEMENT

Determination of Target Share Units
The dollar value of the award, as determined by the Committee, is denominated in Target Share Units based on the closing price of Company Common Stock on the date of the award (__________).

Performance Period
The Performance Period is __________ through __________.

Performance Goals

[INSERT]

Peer Group

[INSERT]

Payout Calculation

[INSERT]

QEP RESOURCES, INC.
CASH INCENTIVE PLAN

PERFORMANCE SHARE UNIT AWARD AGREEMENT

THIS PERFORMANCE SHARE UNIT AWARD AGREEMENT (the “Agreement”) is made as of _______________ (the “Effective Date”), between QEP Resources, Inc., a Delaware corporation (the “Company”), and ______________ (the “Grantee”).

1. Grant of Performance Share Units. Subject to the terms and conditions of this Agreement and the Company’s Cash Incentive Plan (the “Plan”), the Company hereby issues to Grantee the right to receive a number of Performance Share Units calculated in the manner set forth in Appendix A hereto, based on the achievement of one or more Performance Goals that must be attained over a relevant Performance Period, and assuming a target award of ______________ Performance Share Units (the “Target Share Units”). Each Performance Share Unit actually earned and vested in accordance with this Agreement and Appendix A hereto represents the right to receive a cash payment equal to the Fair Market Value of one share of the Company’s no par value common stock (“Common Stock”), subject to Section 3 and the other terms and conditions of this Agreement. Terms not defined herein shall have the meanings ascribed to them in the Plan.

2. Vesting; Termination of Employment; Forfeiture.
General. Except as set forth below, the Grantee will vest and become entitled to any Performance Share Units earned in accordance with this Agreement and Appendix A hereto only if the Grantee remains in the continuous employment of the Company and its Affiliates from the Effective Date through the date such earned Performance Share Units are paid in accordance with Section 3 (the “Vest Date”).

   a) Termination of Employment. If the Grantee terminates employment with the Company and its Affiliates for any reason other than death, Disability, or Retirement prior to the Vest Date, the Grantee shall forfeit any and all interest under this Agreement and shall forfeit the right to receive any Performance Share Units hereunder.

   b) Death, Disability, or Retirement. If the Grantee terminates employment with the Company and its Affiliates on account of death, Disability, or Retirement (as defined below) prior to the last day of the Performance Period, the Grantee shall receive on the Vest Date a *pro rata* portion of the Performance Share Units that would otherwise have been received for the Performance Period, subject to certification by the Committee, in an amount equal to the product of (x) the number of Performance Share Units that would have been earned in accordance with the provisions of Appendix A had Grantee remained in the continuous employment of the Company or its Affiliates through the last day of the Performance Period, *multiplied by* (y) the ratio between (i) the number of full months of employment completed from the first day of the Performance Period to the date of termination of employment and (ii) the number of full months in the Performance Period. If the Grantee terminates employment with the Company and its Affiliates on account of death, Disability, or Retirement on or after the last day of the Performance Period but before the Vest Date, the Grantee shall receive on the Vest Date the Performance Share Units that would have been earned in accordance with the provisions of Appendix A had the Grantee remained in the continuous employment of the Company or its Affiliates through the Vest Date.

"Retirement" shall mean Grantee's voluntary termination of employment with the Company and its Affiliates on or after age 55 with at least 10 years of service; provided that such retirement occurs no earlier than 12 months after the first day of the Performance Period, or such other retirement as shall be approved by the Committee in its discretion.

3. Payment.

a) General. As soon as practicable after the end of the Performance Period the Committee shall determine and certify the number of Performance Share Units that have been earned in accordance with Appendix A and the terms and conditions of this Agreement. Subject to subsection (b), payment for Performance Share Units shall be made in cash on the Vest Date. The amount distributable shall be based on the average closing Company stock price for the fourth quarter of the final year of the Performance Period. All payments shall be made as soon as administratively practicable after the date on which the Committee determines and certifies the number of Performance Share Units that have been earned, but in all events in the calendar year following the calendar year in which the Performance Period ends.

b) Payment in Shares. Notwithstanding anything in the Plan, this Agreement or in Appendix A to the contrary, in lieu of paying the Performance Share Units in cash as provided in subsection (a), the Committee may elect in its discretion to pay some or all of the Performance Share Units in the form of an equal number of actual shares of the Company's (or its successor's) Common Stock or other applicable securities, which shares of Common Stock or other applicable securities shall be delivered to the Grantee under the Company's 2010 Long-Term Stock Incentive Plan (as it may be amended or restated from time to time, or, to the extent applicable, any future or successor equity compensation plan of the Company).

4. Change in Control. Notwithstanding anything in this Agreement or in Appendix A to the contrary, upon the occurrence of a Change in Control (as defined in the Plan), for each Performance Period greater than one year that is outstanding under the Plan as of the date of the Change in Control, a payment will be made in an amount equal to the actual award that would have been earned by the Grantee under the Plan for such Performance Period, based on the level of satisfaction of the Performance Goals that was achieved for the Performance Period in which the Change in Control occurs. Solely for purposes of determining which Performance Periods are taken into account for purposes of the preceding sentence, (i) a Performance Period shall be deemed to be outstanding if the Vest Date has yet to occur for such period as of the date of the Change in Control, even if the actual Performance Period (i.e. the period over which performance is measured) has already ended, and (ii) a Performance Period shall not be deemed to be outstanding if a target award has yet to be established for such period as of the date of the Change in Control.

If the Change in Control is also a "change in control" within the meaning of Section 409A of the Internal Revenue Code (IRC), the Performance Share Units earned (if any) shall be paid on a date selected by the Committee within 30 days after the closing of the transaction that constitutes the change in control. If the Change in Control is not also a "change in control" within the meaning of Section 409A, the Company, or the successor or purchaser, as the case may be, shall make adequate provision for the assumption of the obligation to pay to the Grantee such earned and vested Performance Share Units as soon as administratively practicable in the calendar year in which such amounts would otherwise have been payable to the Grantee as described above.

5. No Rights of a Stockholder. The Grantee shall have no voting or other rights as a stockholder of the Company with respect to this award. The Grantee's right to receive payments earned under this Agreement shall be no greater than the right of any unsecured general creditor of the Company.

6. Adjustments to Performance Share Units. In the event of any stock dividend, extraordinary cash dividend, recapitalization, reorganization, merger, consolidation, split-up, spin-off, combination, exchange of shares, grant of warrants or rights offering to purchase Common Stock at a price materially below fair market value or other similar corporate event affecting the Common Stock, the Committee shall adjust the award issued hereunder in order to preserve the benefits or potential benefits intended to be made available under this Agreement. All adjustments shall be made in the sole and exclusive discretion of the Committee, whose determination shall be final, binding and conclusive. Notice of any adjustment shall be given to Grantee.

7. Notices. Any notice required or permitted to be given under this Agreement shall be in writing and shall be given by e-mail, hand delivery or by first class registered or certified mail, postage prepaid, addressed, if to the Company, to its Corporate Secretary, and if to Grantee, to his or her address now on file with the Company, or to such other address as either may designate in writing. Any notice shall be deemed to be duly given as of the date delivered in the case of e-mail or personal delivery, or as of the second day after enclosed in a properly sealed envelope and deposited, postage prepaid, in a United States post office, in the case of mailed notice.

8. Amendment. Except as provided herein, this Agreement may not be amended or otherwise modified unless evidenced in writing and signed by the Company and Grantee, or as approved by the Committee.

9. Relationship to Plan. Except to the extent this Agreement provides for the discretionary stock settlement of the Target Share Units, this Agreement shall not alter the terms of the Plan. If there is a conflict between the terms of the Plan and the terms of this Agreement, the terms of the Plan shall prevail, provided, however, that the terms of Section 3(b) of this Agreement shall control over any contrary provision of the Plan. Capitalized terms used in this Agreement but not defined herein shall have the meaning given such terms in the Plan.

10. Construction; Severability. The section headings contained herein are for reference purposes only and shall not in any way affect the meaning or interpretation of this Agreement. The invalidity or unenforceability of any provision of this Agreement shall not affect the validity or enforceability of any other provision of this Agreement, and each other provision of this Agreement shall be severable and enforceable to the extent permitted by law.

11. Waiver. Any provision contained in this Agreement may be waived, either generally or in any particular instance, by the Committee appointed under the Plan, but only to the extent permitted under the Plan.

12. Entire Agreement; Binding Effect. Once accepted, this Agreement, the terms and conditions of the Plan, and the award of Performance Share Units set forth herein, constitute the entire agreement between Grantee and the Company governing such award of Performance Share Units, and shall be binding upon and inure to the benefit of the Company and to Grantee and to the Company's and Grantee's respective heirs, executors, administrators, legal representatives, successors and assigns.

13. No Rights to Employment. Nothing contained in this Agreement shall be construed as giving Grantee any right to be retained in the employ of the Company or its Affiliates and this Agreement is limited solely to governing the rights and obligations of Grantee with respect to the Performance Share Units.

14. Governing Law. This Agreement shall be governed by and construed in accordance with the laws of the State of Delaware, without regard to the choice of law principles thereof.

15. Section 409A.

a) The payments and benefits provided hereunder are intended to be exempt from or compliant with the requirements of Section 409A of the IRC. Notwithstanding any provision of this Agreement to the contrary, in the event that the Company reasonably determines that any payments or benefits hereunder are not either exempt from or compliant with the requirements of Section 409A of the IRC, the Company shall have the right to adopt such amendments to this Agreement or adopt such other policies and procedures (including amendments, policies and procedures with retroactive effect), or take any other actions, that are necessary or appropriate (i) to preserve the intended tax treatment of the payments and benefits provided hereunder, to preserve the economic benefits with respect to such payments and benefits, and/or (ii) to exempt such payments and benefits from Section 409A of the IRC or to comply with the requirements of Section 409A of the IRC and thereby avoid the application of penalty taxes thereunder; provided, however, that this Section does not, and shall not be construed so as to, create any obligation on the part of the Company to adopt any such amendments, policies or procedures or to take any other such actions or to indemnify Grantee for any failure to do so.

b) It is not intended that any payments to be made pursuant to this Agreement would be made on account of Grantee's "separation from service" within the meaning of Section 409A of the IRC. However, in the event that any payment is deemed to be so made, and if Grantee is a "specified employee" as defined in Section 409A on the date of such "separation from service," then notwithstanding anything to the contrary herein, no payment shall be made prior to the earliest date on which payment may be made under Section 409A(a)(2)(B)(i) (the six month delay rule for specified employees).

IN WITNESS WHEREOF, the parties have executed this Agreement as of the day and year first above written.

GRANTEE QEP RESOURCES, INC.

by_______

[Name] [NAME]

[TITLE]

APPENDIX A
TO THE PERFORMANCE SHARE UNIT AWARD AGREEMENT

Determination of Target Share Units
The dollar value of the award, as determined by the Committee, is denominated in Target Share Units based on the closing price of Company Common Stock on the date of the award (__________).

Performance Period
The Performance Period is __________ through __________.

Performance Goals

[INSERT]

Payout Calculation

[INSERT]

Exhibit 12.1

QEP Resources, Inc.
Ratio of Earnings to Fixed Charges

	Year Ended December 31,				
	2014	2013	2012	2011	2010
Earnings					
Income from continuing operations before income taxes and adjustment for income or loss from equity investees	**$ (642.0)**	$ 112.2	$ 0.5	$ 183.6	$ 321.0
Add (deduct):					
Fixed charges	**175.6**	167.8	128.7	95.7	89.8
Distributed income from equity investees	**0.3**	0.2	0.1	0.1	0.2
Capitalized interest	**—**	(2.0)	(3.4)	(3.0)	(3.1)
Total earnings	**$ (466.1)**	$ 278.2	$ 125.9	$ 276.4	$ 407.9
Fixed Charges					
Interest expense	**$ 172.9**	$ 163.3	$ 122.9	$ 90.0	$ 84.4
Capitalized interest	**—**	2.0	3.4	3.0	3.1
Estimate of the interest within rental expense	**2.7**	2.5	2.4	2.7	2.3
Total Fixed Charges	**$ 175.6**	$ 167.8	$ 128.7	$ 95.7	$ 89.8
Ratio of Earnings to Fixed Charges	**(2.7)**	1.7	1.0	2.9	4.5

Exhibit 21.1

QEP Resources, Inc.
Subsidiaries of the Company

Name	State of Organization
QEP Energy Company [(1)]	Texas
QEP Marketing Company [(1)]	Utah
QEP Field Services Company [(1)]	Delaware
Roden Participants, LTD [(2)]	Texas
Clear Creek Storage Company, LLC [(3)]	Utah
Wyoming Peak Land Company, LLC [(4)]	Wyoming
QEP Oil & Gas Company [(3)]	Delaware
Haynesville Gathering LP [(5)]	Delaware
Perry Land Management Co. LLC [(6)]	Oklahoma

[(1)] 100% owned by QEP Resources, Inc.
[(2)] 14% owned by QEP Energy Company
[(3)] 100% owned by QEP Marketing Company
[(4)] 100% owned by QEP Energy Company
[(5)] 99% owned by QEP Oil and Gas Company and 1% owned by QEP Marketing Company
[(6)] 100% owned by QEP Field Services Company

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 of QEP Resources, Inc. (No. 333-165805 and No. 333-179709), and to the incorporation by reference in the Registration Statements on Form S-8 of QEP Resources, Inc. (Nos. 333-167726 and 333-167727), of our report dated February 24, 2015, relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

PricewaterhouseCoopers LLP
Houston, Texas
February 24, 2015

Exhibit 23.2

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580 FAX (303) 623-4258

621 SEVENTEENTH STREET SUITE 1550 DENVER, COLORADO 80293 TELEPHONE 303) 623-9147

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

As independent petroleum engineers, we hereby consent to the reference of our appraisal reports relating to the proved gas and oil reserves of QEP Energy Company in the Annual Report on Form 10-K of QEP Resources, Inc. as of the years ended December 31, 2011, 2012, 2013 and 2014 incorporated herein by reference into Registration Statement Nos. 333-165805 and 333-179709 on Form S-3, 333-167726 and 333-167727 on Form S-8.

/s/ Ryder Scott Company, L.P.

Ryder Scott Company, L.P.

Denver, Colorado
February 24, 2015

DEGOLYER AND MACNAUGHTON
5151 SAN FELIPE
SUITE 950
HOUSTON, TEXAS 77056

TELEPHONE
(713) 273-8300
FAX
(713) 784-1972
WWW. DEMAC.COM

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

As independent petroleum engineers, we hereby consent to the reference of our appraisal reports relating to the proved gas and oil reserves of QEP Energy Company in the Annual Report on Form 10-K of QEP Resources, Inc. as of the year ended December 31, 2014 incorporated herein by reference into Registration Statement Nos. 333-165805 and 333-179709 on Form S-3, 333-167726 and 333-167727 on Form S-8.

/s/DeGolyer and MacNaughton

DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716
February 24, 2015

Exhibit 24

POWER OF ATTORNEY

We, the undersigned directors of QEP Resources, Inc., hereby severally constitute Charles B. Stanley and Richard J. Doleshek, and each of them acting alone, our true and lawful attorneys, with full power to them and each of them to sign for us, and in our names in the capacities indicated below, the Annual Report on Form 10-K for 2014 and any and all amendments to be filed with the Securities and Exchange Commission by QEP Resources, Inc., hereby ratifying and confirming our signatures as they may be signed by the attorneys appointed herein to the Annual Report on Form 10-K for 2014 and any and all amendments to such Report.

Witness our hands on the respective dates set forth below.

Signature	Title	Date
/s/ Charles B. Stanley Charles B. Stanley	Chairman of the Board President and Chief Executive Officer	2/24/2015
/s/ Phillip S. Baker, Jr. Phillips S. Baker, Jr.	Director	2/24/2015
/s/ Julie A. Dill Julie A. Dill	Director	2/24/2015
/s/ L. Richard Flury L. Richard Flury	Director	2/24/2015
/s/ Robert F. Heinemann Robert F. Heinemann	Director	2/24/2015
/s/ Robert E. McKee III Robert E. McKee III	Director	2/24/2015
/s/ M. W. Scoggins M. W. Scoggins	Director	2/24/2015
/s/ David A. Trice David A. Trice	Director	2/24/2015
/s/ William L. Thacker III William L. Thacker III	Director	2/24/2015

Exhibit 31.1

CERTIFICATION

I, Charles B. Stanley, certify that:

1. I have reviewed this report of QEP Resources, Inc. on Form 10-K for the period ended December 31, 2014;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 24, 2015

/s/ Charles B. Stanley

Charles B. Stanley
Chairman, President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Richard J. Doleshek, certify that:

1. I have reviewed this report of QEP Resources, Inc. on Form 10-K for the period ended December 31, 2014;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 24, 2015

/s/ Richard J. Doleshek

Richard J. Doleshek

Executive Vice President, Chief Financial Officer, Treasurer and Chief Accounting Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with this report of QEP Resources, Inc. (the Company) on Form 10-K for the period ended December 31, 2014, as filed with the Securities and Exchange Commission on the date hereof (the Report), Charles B. Stanley, Chairman, President and Chief Executive Officer of the Company, and Richard J. Doleshek, Executive Vice President, Chief Financial Officer, Treasurer and Chief Accounting Officer of the Company, each hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

QEP RESOURCES, INC.

February 24, 2015

/s/ Charles B. Stanley
Charles B. Stanley
Chairman, President and Chief Executive Officer

February 24, 2015

/s/ Richard J. Doleshek
Richard J. Doleshek
Executive Vice President,
Chief Financial Officer, Treasurer and
Chief Accounting Officer

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580
FAX (303) 623-4258
621 SEVENTEENTH STREET SUITE 1550 DENVER, COLORADO 80293 TELEPHONE 303) 623-9147

January 23, 2015

QEP Energy Company
1050 Seventeenth Street, Suite 800
Denver, Colorado 80265

Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of QEP Energy Company (QEP) as of December 31, 2014. The subject properties are located in the states of Arkansas, Colorado, Kansas, Louisiana, Montana, New Mexico, North Dakota, Oklahoma, Texas, Utah and Wyoming. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 23, 2015 and presented herein, was prepared for public disclosure by QEP in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott account for a portion of QEP's total net proved reserves as of December 31, 2014. Based on information provided by QEP, the third party estimate conducted by Ryder Scott addresses 86.5 percent of the total proved developed net liquid hydrocarbon reserves, 97.1 percent of the total proved developed net gas reserves, 75.7 percent of the total proved undeveloped net liquid hydrocarbon reserves, and 95.6 percent of the total proved undeveloped net gas reserves of QEP.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2014, are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized below.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
QEP Energy Company
As of December 31, 2014

	Proved			
	Developed			Total
	Producing	Non-producing	Undeveloped	Proved
Net Remaining Reserves				
Oil/Condensate - Mbarrels	88,841.0	1,409.2	52.275.4	137,525.6
Plant Products - Mbarrels	42,803.9	3,082.9	36,713.0	82,599.8
Gas - MMCF	1,173.012	78,527	983,983	2,235.522
Income Data (M$)				
Future Gross Revenue	$12,876,386	$526,305	$9,338,053	$22,740,744
Deductions	4,510,076	247,001	4,955,726	9,712,803
Future Net Income (FNI)	$ 8,366,310	$279,304	$4,382,327	$13,027,941
Discounted FNI @ 10%	$ 4,855,886	$144,418	$1,777,058	$ 6,777,362

Liquid hydrocarbons are expressed in thousands of standard 42 gallon barrels (MBarrels). All gross 8/8ths gas production volumes are forecast before shrinkage and net gas production volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars (M$).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package Aries TM System Petroleum Economic Evaluation Software, a copyrighted program of Halliburton. The program was used at the request of QEP. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding . The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, recompletion costs, development costs, and certain abandonment costs net of salvage. Other deductions are very minor net profits interest payments. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist, nor does it include any adjustment for cash on hand or undistributed income. Future net income does not include depreciation, depletion and amortization affects nor any impairment conditions. Liquid hydrocarbon reserves account for approximately 59 percent and gas reserves account for the remaining 41 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income (M$) As of December 31, 2014
Discount Rate Percent	Total Proved
5	$8,949,323
9	$7,124,375
15	$5,448,949
20	$4,557,667

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-1 O(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "Petroleum Reserves Definitions" is included as an attachment to this report.

The various proved reserve status categories are defined under the attachment entitled "Petroleum Reserves Status Definitions and Guidelines" in this report. The proved developed nonproducing reserves included herein consist of wells that are waiting on completion, behind pipe, shut-in, or temporarily abandoned.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves, and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At QEP's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward". The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

QEP's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which QEP owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-1 O(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely than not to be achieved." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods, the volumetric method, analogy, or a combination of methods. All of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis which utilized extrapolations of historical production data available through October 2014 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by QEP and were considered sufficient for the purpose thereof.

Approximately 99 percent of the proved developed non-producing and undeveloped reserves included herein were estimated by analogy. Approximately 1 percent of the proved developed nonproducing and undeveloped reserves were estimated by the volumetric method. The volumetric analysis utilized pertinent well data furnished to Ryder Scott by QEP that were available through October 2014. The data utilized from the analogues as well as the data incorporated into our volumetric analysis were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash\ flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data that cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-1 O(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

QEP has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by QEP with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by QEP. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by QEP. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, 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, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

QEP furnished us with the above mentioned average prices in effect on December 31, 2014. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used for the geographic area included in the report. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by QEP.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the "average realized prices." The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$94.99/Bbl	$82.20/Bbl
	NGLs	WTI Cushing	$94.99/Bbl	$36.04/Bbl
	Gas	Henry Hub	$4.35/MMBTU	$4.49/MCF

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations

Costs

Operating costs for the leases and wells in this report were furnished by QEP and are based on the operating expense reports of QEP and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells.

The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by QEP. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by QEP and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were significant. The estimates of the net abandonment costs furnished by QEP were accepted without independent verification.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with QEP's plans to develop these reserves as of December 31, 2014. The implementation of QEP's development plans as presented to us and incorporated herein is subject to the approval process adopted by QEP's management. As the result of our inquiries during the course of preparing this report, QEP has informed us that the development activities included herein have been subjected to and received the internal approvals required by QEP's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to QEP. Additionally, QEP has informed us that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2014, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by QEP were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to QEP. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by QEP.

QEP makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, QEP has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 and/or S-8 of QEP of the references to our name as well as to the references to our third party report for QEP, which appears in the December 31, 2014 annual report on Form 10-K of QEP. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by QEP.

We have provided QEP with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by QEP and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

Very truly yours,

RYDER SCOTT COMPANY, LP.
TBPE Firm Registration No. F-1580

/s/James L. Baird
James L. Baird, P.E.
Colorado License No 41521
Managing Senior Vice President
[Seal]

/s/ Richard J. Marshall
Richard J. Marshall, P.E.
Colorado License No. 23260
Vice President
[Seal]

JLB-RJM (DPR)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Richard J. Marshall was the primary technical person responsible for overseeing the estimate of the future net reserves and income.

Marshall, an employee of Ryder Scott Company, L.P. (Ryder Scott) beginning in 1981, is a Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies. Before joining Ryder Scott, Marshall served in a number of engineering positions with Texaco, Phillips Petroleum, and others. For more information regarding Mr. Marshall's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Marshall earned a B.S. in Geology from the University of Missouri in 1974 and a M.S. in Geological Engineering from the University of Missouri at Rolla in 1976. Marshall is a registered Professional Engineer in the State of Colorado. He is a member of the Society of Petroleum Engineers, Wyoming Geological Association, Rocky Mountain Association of Geologists and the Society of Petroleum Evaluation Engineers.

Based on Marshall's educational background, professional training and more than 30 years of practical experience in the estimation and evaluation of petroleum reserves, Marshall has attained the professional qualifications as a Reserves Estimator and Reserves Auditor as set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

Exhibit 99.2

DEGOLYER AND MACNAUGHTON
500 I SPRING VALLEY ROAD
SUITE 800 EAST
DALLAS, TEXAS 75244

This is a digital representation of a DeGolyer and MacNaughton report.

Each file contained herein is intended to be a manifestation of certain data in the subject report and as such is subject to the definitions, qualifications, explanations, conclusions, and other conditions thereof. The information and data contained in each file may be subject to misinterpretation; therefore, the signed and bound copy of this report should be considered the only authoritative source of such information.

DEGOLYER AND MACNAUGHTON
500 I SPRING VALLEY ROAD
SUITE 800 EAST
DALLAS, TEXAS 75244

February 6, 2015

QEP Energy Company
1050 17th Street
Suite 500
Denver, Colorado 80265

Ladies and Gentlemen:

Pursuant to your request, we have prepared estimates of the extent and value of the net proved crude oil, condensate, natural gas liquids (NGL), and natural gas reserves, as of December 31, 2014, of certain selected properties in which QEP Energy Company (QEP) has represented that it owns an interest. This evaluation was completed on February 6, 2015. QEP has represented that these properties account for 9.5 percent on a thousand barrels of oil equivalent basis of QEP's net proved reserves as of December 31, 2014. The properties are located in Texas. The net proved reserves estimates prepared by us have been prepared in accordance with the reserves definitions of Rules 4-lO(a) (1}-(32) of Regulation S--X of the Securities and Exchange Commission (SEC) of the United States. This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S-K and is to be used for inclusion in certain SEC filings by QEP.

Reserves estimates included herein are expressed as net reserves. Gross reserves are defined as the total estimated petroleum to be produced from these properties after December 31, 2014. Net reserves are defined as that portion of the gross reserves attributable to the interests owned by QEP after deducting all interests owned by others.

Estimates of oil, condensate, NGL, and natural gas reserves and future net revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such reserves and revenue estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Data used in this evaluation were obtained from reviews with QEP personnel, from QEP files, from records on file with the appropriate regulatory agencies, and from public sources. In the preparation of this report we have relied, without independent verification, upon such information furnished by QEP with respect to property interests, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of this report.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)." The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production or to the limit of the production licenses as appropriate.

Gas quantities estimated herein are expressed as sales gas. Sales gas is defined as that portion of the total gas to be delivered into a gas pipeline for sale after separation, processing, fuel use, and flare. Gas reserves are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at the legal pressure base of the state in which the interest is located. Condensate reserves estimated herein are those to be recovered by conventional lease separation. NGL reserves are those attributed to the leasehold interests according to processing agreements. Oil, condensate, and NGL reserves included in this report are expressed in terms of barrels representing 42 United States gallons per barrel.

Definition of Reserves

Petroleum reserves included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used in this report are in accordance with the reserves definitions of Rules 4-lO(a) (1}-(32) of Regulation S-X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

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

(i) The area of the reservoir considered as proved includes:
(A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Developed oil and gas reserves - Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) 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; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped oil and gas reserves - Undeveloped oil and gas reserves are 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in [section 210.4-10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

The development status shown herein represents the status applicable on December 31, 2014. In the preparation of this study, data available from wells drilled on the appraised properties through December 31, 2014, were used in estimating gross ultimate recovery. When applicable, gross production estimated to December 31, 2014, was deducted from gross ultimate recovery to arrive at the estimates of gross reserves as of December 31, 2014. Production data through September 2014 were available for most properties.

Our estimates of QEP's net proved reserves attributable to the reviewed properties are based on the definition of proved reserves of the SEC and are as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcD, and thousands of barrels of oil equivalent (Mboe):

	Estimated by DeGolyer and MacNaughton Net Proved Reserves as of December 31, 2014			
	Oil and Condensate (Mbbl)	NGL (Mbbl)	Natural Gas (MMcf)	Oil Equivalent (Mboe)
Proved				
Developed Producing	13,984	6,282	34,496	26,349
Developed Nonproducing	70	38	220	144
Undeveloped	20,943	7,706	44,825	36,120
Total Proved	**34,997**	**14,026**	**81,541**	**62,613**

Note: Gas is converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.

Primary Economic Assumptions

Revenue values in this report are expressed in terms of estimated future gross revenue, future net revenue, and present worth of future net revenue. Future gross revenue is defined as that revenue to be realized from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting estimated production taxes, ad valorem taxes, operating, gathering, processing expenses, capital costs, and abandonment costs from the future gross revenue. Present worth of future net revenue is calculated by discounting the future net revenue at the arbitrary rate of 10 percent per year compounded monthly over the expected period of realization.

Revenue values in this report were estimated using the initial prices and expenses provided by QEP. Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The prices used in this report are based on SEC guidelines. The assumptions used for estimating future prices and expenses are as follows:

Oil, Condensate, and NGL Prices

Oil, condensate, and NGL prices were calculated using specified differentials for each lease to a price of $94.99 per barrel. No escalation was applied to the prices. The West Texas Intermediate Cushing price of $94.99 per barrel is the 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. The volume-weighted average price for the proved reserves over the lives of the properties was $87.17 per barrel for oil and condensate. The volume-weighted average price for the proved reserves over the lives of the properties was $34.26 per barrel for NGL.

Natural Gas Prices

Natural gas prices were calculated using specified differentials and British thermal unit factors for each lease supplied by QEP to a Henry Hub price of $4.35 per million British thermal units (MMBtu). No escalation was applied to the prices. The Henry Hub gas price of $4.35 per MMBtu is the 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to December 31, 2014. The volume-weighted average price for the proved reserves over the lives of the properties was $3.807 per thousand cubic feet of gas.

Production and Ad Valorem Taxes

Production taxes are calculated using the tax rates for Texas, including where appropriate, abatements for enhanced recovery programs. Ad valorem taxes are calculated using rates provided by QEP based on recent payments.

Operating Expenses, Capital Costs, and Abandonment Costs

Operating expenses and capital costs, based on information provided by QEP, were used in estimating future costs required to operate the properties. In certain cases, future costs, either higher or lower than existing costs, may have been used because of anticipated changes in operating conditions. Abandonment costs were included for all properties. These costs were not escalated for inflation.

The estimated future revenue and expenditures attributable to the production and sale of QEP's net proved reserves of the properties appraised, as of December 31, 2014, are summarized in thousands of dollars (M$) as follows:

	Proved			
	Developed Producing (M$)	**Developed Nonproducing (M$)**	**Undeveloped (M$)**	**Total Proved (M$)**
Future Gross Revenue	1,572,779	8,175	2,260,524	3,841,478
Production and Ad Valorem Taxes	107,885	562	153,252	261,699
Operating Expenses	524,004	2,251	448,664	974,919
Capital and Abandonment Costs	9,590	25	823,056	832,671
Future Net Revenue	931,300	5,337	835,552	1,772,189
Present Worth at 10 Percent	552,041	3,550	167,278	722,869

Note: Future income taxes have not been taken into account in the preparation of these estimates.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its oil and gas reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2014, estimated oil and gas reserves.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, condensate, natural gas liquids, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, *Extractive Industries - Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the Financial Accounting Standards Board and Rules 4-lO(a) (1)-(32) of Regulation S-X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (8), and 1203(a) of Regulation S-K of the Securities and Exchange Commission; provided, however, that (i) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein and (ii) estimates of the proved developed and proved undeveloped reserves are not presented at the beginning of the year.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, · are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in QEP. Our fees were not contingent on the results of our evaluation. This letter report has been prepared at the request of QEP. DeGolyer and MacNaughton has used all assumptions, data, procedures, and methods that it considers necessary and appropriate to prepare this report.

Submitted,

/s/ DeGOLYER and MacNAUGHTON
DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

/s/ Gregory K. Graves
Gregory K. Graves, P.E.
Senior Vice President
DeGolyer and MacNaughton

CERTIFICATE of QUALIFICATION

I, Gregory K. Graves, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which company did prepare the letter report addressed to QEP dated February 6, 2015, and that I, as Senior Vice President, was responsible for the preparation of this letter report.

2. That I attended the University of Texas at Austin, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in the year 1984; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the International Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers; and that I have in excess of 30 years of experience in oil and gas reservoir studies and reserves evaluations.

/s/ Gregory K. Graves, P.E.
Gregory K. Graves, P.E.
Senior Vice President
DeGolyer and MacNaughton