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, 2013

001-34778
(Commission File No.)

QEP Resources, Inc.

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 500, 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. ☐

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, 2013): $4,973,494,170.

At January 31, 2014, there were 179,332,240 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 2014 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 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 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 500, 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, and Section 21E of the Securities Exchange Act of 1934, as amended. 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:

- QEP’s growth strategies;
- natural gas, oil and NGL prices and factors affecting the volatility of such prices;
- plans to drill or participate in wells and to defer completion of wells;
- results from planned drilling operations and production operations;
- QEP's cash operating costs and ability to control costs;
- ability to pursue acquisition opportunities;
- proforma results for acquired properties;
- expected restructuring costs;
- impact of the Dodd-Frank Act and expectation that QEP's derivatives will not need to be cleared on exchanges;
- the Company's liquidity;
- plans to divest of non-core assets and use of proceeds from such divestitures;
- plans to separate the midstream business;
- refinery and pipeline and other transportation constraints;
- seasonality of QEP's operating results;
- loss of employees;
- assumptions regarding equity compensation;
- obligation under drilling contracts;
- recognition of compensation costs related to equity compensation grants;
- expected gain on sale of assets;
- amount and allocation of forecasted capital expenditures and plans for funding capital expenditures and operating expenses;
- estimated accrual for loss contingencies and other items;
- impact of lower or higher commodity prices and interest rates;
- effect of recession;
- plans to enter into derivative contracts for a portion of forecasted production;
- future expenses and operating costs;

- operation of processing plants at assumed capacities;
- the amount and timing of the settlement of derivative contracts;
- occurrence of unrealized derivative gains and losses;
- impact of nonperformance by trade creditors or joint venture partners;
- the outcome of contingencies such as legal proceedings;
- expected contributions to the Company’s pension plans and returns from plan assets;
- impact of recently issued accounting pronouncements;
- the significance of Adjusted EBITDA as a measure of cash flow and liquidity;
- payment of dividends;
- potential for future asset impairments; and
- estimated future purchase accounting adjustments.

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 natural 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 capacity;
- QEP's ability to successfully integrate acquired assets or dispose of non-core assets;
- the outcome of contingencies such as legal proceedings;
- permitting delays;
- operating risks such as unexpected drilling conditions;
- weather conditions;
- changes in maintenance and construction costs, including possible inflationary pressures;
- 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;
- substantial liabilities from legal proceedings and environmental claims;
- failure of internal controls and procedures;
- elimination of federal income tax deductions for oil and gas exploration and development costs;
- future opportunities that QEP's Board of Directors may determine present greater potential value to stockholders than planned divestiture of assets;
- regulatory approvals and compliance with contractual obligations;
- actions, or inaction, by federal, state, local or tribal governments;
- fluctuations in processing margins;
- unexpected changes in costs for constructing, modifying or operating midstream facilities;
- lack of, or disruptions in, adequate and reliable transportation for QEP's products; 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 Utilizes refrigeration 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 4-10(a)(6).

development well A well drilled within the proved area of an oil or gas reservoir to the depth of a horizon known to be productive.

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.

FERC The Federal Energy Regulatory Commission.

frac spread The difference between the market value for natural gas liquids (NGL) extracted from the natural gas stream and the market value of the Btu-equivalent volume of natural gas required to replace the extracted liquids.

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.

keep-whole processing Processing which occurs under a contract where the Company retains and sells NGL extracted at its processing plants and keeps the customer "whole" by buying and delivering a Btu-equivalent amount of natural gas to the customer.

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 Light Louisiana 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 WTI The price of West Texas Intermediate crude oil on the New York Mercantile Exchange.

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

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

probable reserves 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.

proved properties Properties with proved reserves.

proved reserves Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. See 17 C.F.R. Section 4-10(a)(22).

reserves Estimated remaining quantities of natural gas, crude oil and related substances anticipated to be economically producible 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. See 17 C.F.R. Section 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.

resource play Refers to regionally distributed oil and natural gas accumulation as opposed to conventional plays which are more limited in their area 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 un-drilled acreage, or from existing wells where a relatively major expenditure is required for re-completion. See 17 C.F.R. Section 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 2013
PART I

ITEM 1. BUSINESS

Nature of Business

QEP Resources, Inc. (QEP or the Company) is a holding company with three major lines of business: oil and gas exploration and production; midstream field services; and energy marketing. These businesses are conducted through the Company’s three principal subsidiaries:

- QEP Energy Company (QEP Energy) acquires, explores for, develops and produces gas, oil, and NGL;
- QEP Field Services Company (QEP Field Services), which includes the ownership and operations of QEP Midstream Partners, LP (QEP Midstream), provides midstream field services, including gathering of natural gas, oil and NGL, natural gas processing, compression, and treating services, for affiliates and third parties, and;
- QEP Marketing Company (QEP Marketing) markets affiliate and third-party oil and gas, and owns and operates an underground gas storage reservoir.

QEP's operations are focused in two major regions: the Northern Region (primarily in North Dakota, Wyoming and Utah) and the Southern Region (primarily in Oklahoma, Louisiana and the Texas Panhandle) 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 (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.

In connection with the reorganization, QEP renamed its subsidiaries as follows:

- QEP Energy Company (formerly Questar Exploration and Production Company);
- QEP Field Services Company (formerly Questar Gas Management Company); and
- QEP Marketing Company (formerly Questar Energy Trading Company).

The financial information presented in this Annual Report on Form 10-K presents QEP's financial results as an independent company separate from Questar.

Financial and Operating Highlights

Our financial and operating highlights for 2013 include:

- Generated net income of $159.4 million, or $0.89 per diluted share, an increase of 24% from 2012;
- Generated Adjusted EBITDA (a non-GAAP financial measure defined and reconciled in Item 7 of Part II of this Annual Report on Form 10-K) of $1,536.7 million, up from $1,409.0 million in 2012;
- Increased liquids (oil and NGL) production by 29% to 90.1 Bcfe;
- Increased total proved reserves 3% to 4.1 Tcfe and increased liquid (oil and NGL) proved reserves by 15% to 1.5 Tcfe;
- Added 783.8 Bcfe of proved reserves from extensions and discoveries;
- QEP Field Services' gathering throughput volumes, NGL sales volumes and fee-based processing volumes decreased by 13%, 37% and 1%, respectively;
- Recorded $105.7 million of gain on sales of several non-core oil and gas properties;
- Completed the initial public offering of limited partner interests in QEP Midstream (NYSE: QEPM) raising net proceeds of $449.6 million; and

- Completed an acquisition of oil and gas properties in the Permian Basin for approximately $950.0 million, subject to customary purchase price adjustments, during the first quarter of 2014.

Strategies

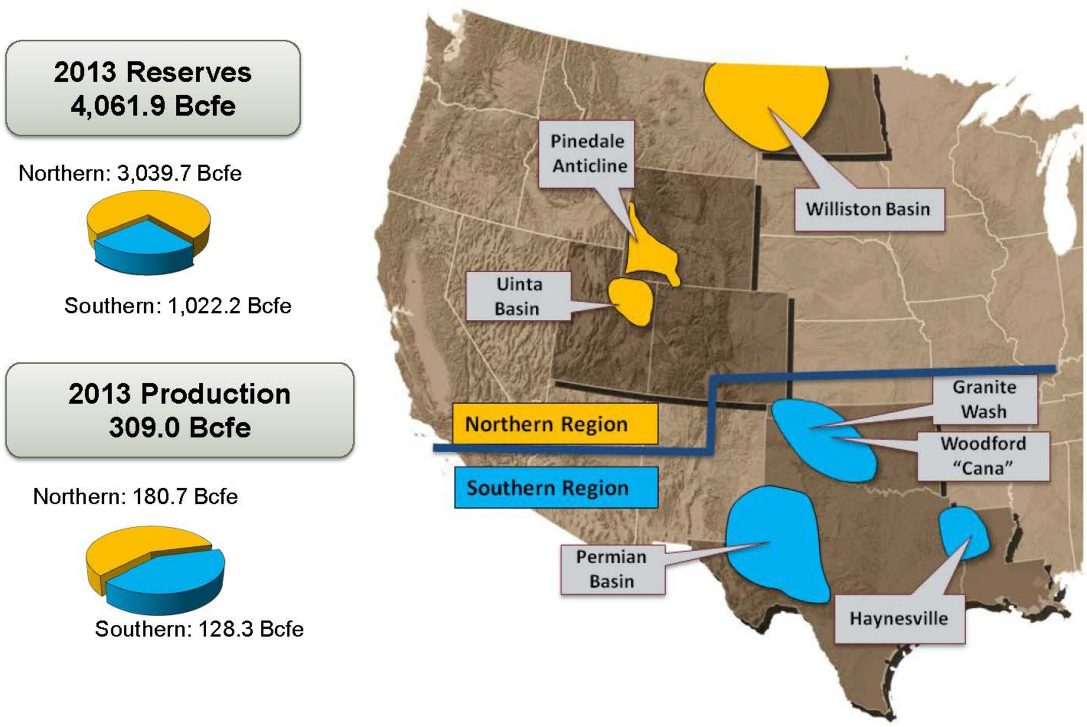
We create value for our shareholders through returns-focused growth, superior execution and a low cost structure. To achieve these objectives we strive to:

- 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;
- maximize the value of our midstream assets;
- actively market our QEP Energy 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 allows us the necessary financial flexibility with which to invest in organic growth and potential acquisition opportunities, as they may arise.

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 a large inventory of identified development drilling locations, primarily in the Williston Basin in North Dakota; the Pinedale Anticline in western Wyoming; the Uinta Basin in eastern Utah; the Anadarko Basin in Oklahoma and Texas; the Haynesville/Cotton Valley in northwestern Louisiana and other proven properties in Wyoming, Colorado and Utah. During the first quarter of 2014, QEP Energy acquired oil and gas properties in the Permian Basin of Texas for an aggregate purchase price of $950.0 million, subject to customary 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 260 vertical producing wells in the Permian Basin, which creates a new core area of operation for QEP Energy.

For 2014, QEP plans to allocate approximately 94% of its capital budget to E&P activities, including capital expenditures allocated to the properties acquired in the Permian Basin Acquisition. The following map illustrates the location of the Company's significant exploration and production activities, its Northern and Southern Regions described elsewhere in this report, and related reserve and production data as of December 31, 2013:



QEP Energy generated approximately 86%, 81%, and 77% of the Company's Adjusted EBITDA (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, 2013, 2012 and 2011, respectively. QEP Energy operates in two core regions – the Northern Region (including the states of Wyoming, Utah, Colorado, and North Dakota) and the Southern Region (including the states of Oklahoma, Texas and Louisiana). The Northern Region contributed 58% of 2013 production while the Southern Region contributed 42%. QEP Energy reported 4,061.9 Bcfe of estimated proved reserves as of December 31, 2013, up 125.8 Bcfe from 2012. Of those estimated proved reserves, approximately 75%, or 3,039.7 Bcfe, were located in the Northern Region at December 31, 2013, compared to 73%, or 2,875.6 Bcfe, at December 31, 2012. The remaining 25%, or 1,022.2 Bcfe, were located in the Southern Region at December 31, 2013, compared to 27%, or 1,060.5 Bcfe, at December 31, 2012. Approximately 53% of the total proved reserves reported by QEP Energy at December 31, 2013, were developed and approximately 37% of the total proved reserves were comprised of oil and NGL, up from 33% at December 31, 2012.

QEP Energy faces competition in every part of its business, including the acquisition of producing leaseholds and 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 priced acreage containing undeveloped reserves and identify and develop the reserves in a low-cost and efficient manner.

The Company seeks to acquire, develop and produce oil and gas from resource plays in its core areas of operation and expand into new areas where it can capitalize on its operating expertise. Since the existence and distribution of hydrocarbons in resource plays is well understood, development of these accumulations has lower risk than conventional discrete hydrocarbon accumulations. Resource plays typically require many wells, drilled at high density, to fully develop and produce the hydrocarbon accumulations. Development of QEP Energy's resource play accumulations 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 continues to conduct some exploratory drilling to determine the commerciality of its inventory of unproven leaseholds. 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 the first quarter of 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 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 and may require financial guarantees or prepayments from parties that fail to meet its credit criteria.

Midstream Field Services – QEP Field Services

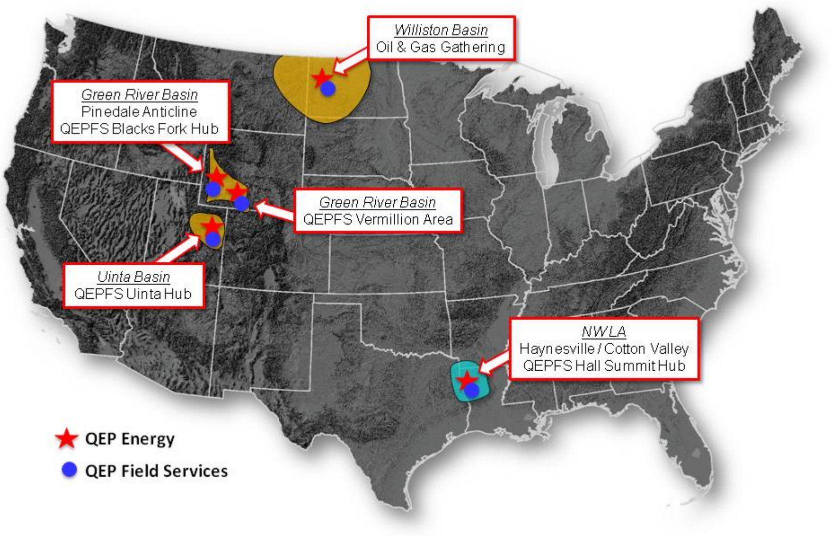
QEP Field Services provides midstream services (gathering, processing and treating) to QEP Energy and third-party customers, including major and independent producers. QEP generates revenues from its midstream activities through a variety of agreements including fee-based gathering and processing agreements and keep-whole processing agreements.

In August 2013, QEP completed the initial public offering (the IPO) of QEP Midstream, a publicly traded master limited partnership formed by QEP to own, operate, acquire and develop certain midstream energy assets. QEP Midstream is consolidated into QEP as it is a majority-owned and controlled subsidiary. Refer to Note 3 - QEP Midstream, in Part II, Item 8 of this Annual Report on Form 10-K for detailed information on the IPO.

In December 2013, after a review of strategic alternatives to maximize the value of its midstream assets, QEP's Board of Directors authorized the Company to develop a plan to separate the business of QEP Field Services, including the Company's interest in QEP Midstream, from QEP.

For 2014, QEP plans to allocate approximately 4% of its capital budget to QEP Field Services to grow its midstream business, including the construction of additional gathering facilities in the Uinta Basin as well as an expansion of the Vermillion processing plant.

The following map illustrates QEP Field Services' areas of operations and the locations corresponding with QEP Energy's operating areas:



QEP Field Services generated approximately 14%, 19%, and 23% of the Company's Adjusted EBITDA (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 the years ended December 31, 2013, 2012 and 2011, respectively. QEP Field Services owns various natural gas gathering, treating and processing facilities as well as a 57.8% interest in QEP Midstream and 38% of Uintah Basin Field Services, LLC (UBFS).

QEP Midstream's assets currently consist of ownership interests in four gathering systems and two FERC regulated pipelines, which provide oil and gas gathering and transportation services. These assets are located in, or within close proximity to, the Green River Basin located in Wyoming and Colorado, the Uinta Basin located in eastern Utah, and the Williston Basin located in North Dakota.

Fee-based gathering and processing revenues represented 82%, 77% and 70% of QEP Field Services' net operating revenues (revenues less plant shrink and transportation costs) during the years ended December 31, 2013, 2012 and 2011, respectively. Approximately 55%, 41%, and 35% of QEP Field Services' 2013, 2012 and 2011, net gas processing revenues (processing revenues less plant shrink) were derived from fee-based processing agreements. The remaining revenues were derived from keep-whole processing agreements. A keep-whole contract exposes QEP Field Services to frac-spread risk while a fee-based contract eliminates direct commodity price exposure. To further reduce volatility associated with keep-whole contracts, QEP Field Services may enter into forward-sales contracts for NGL or NGL price derivatives and equivalent gas volume derivatives with the intent to lock in a processing margin.

QEP Field Services faces regional competition with varying competitive factors in each basin. QEP Field Services' gathering and processing business competes with interstate and intrastate pipelines, producers and independent gatherers and processors. Numerous factors impact a customer's choice of a gathering or processing service provider, including location, rate, term, pressure obligations, timeliness of services, and contract structure. QEP Field Services provides natural gas gathering, processing and treating services to affiliates and third-party producers who own producing natural gas fields in the Rocky Mountain region, the Williston Basin and northwest Louisiana. In addition to its natural gas operations, QEP Field Services also provides oil and water gathering and handling to affiliates and third-party producers in the Rocky Mountain region and the Williston Basin. QEP Field Services' gas gathering, processing and treating services are generally provided under long-term agreements.

Energy Marketing—QEP Marketing

QEP Marketing provides wholesale marketing and sales of affiliate and third-party gas, oil and NGL and generated less than 1% of the Company's Adjusted EBITDA (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, 2013, 2012 and 2011. 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.

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 substantial compliance with currently applicable laws and regulations and has not experienced any material adverse effect arising from these requirements, there is no assurance that this trend will continue in the future. Due to the myriad of complex federal, state, tribal and local regulations that may affect 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 Item 1A - Risk Factors, in this Annual Report on Form 10-K.

Regulation of Exploration, Production, Gathering and Processing 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 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, dehydrators and gas processing plant components.

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 legal measures to reduce emissions of GHG, primarily through the development of GHG inventories, greenhouse gas permitting and/or regional GHG cap and trade programs; however, some states have required or proposed some level of methane leak detection monitoring and repair for upstream and midstream oil and gas activities.

Clean Water Act and Safe Drinking Water Act. The Clean Water Act and similar state laws regulate discharges of wastewater, oil, and other pollutants to surface water bodies, such as 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 supports disclosure of 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. 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. 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 2014. 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. 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. The Non-Government Organization Environmental Integrity Project has filed a petition for rulemaking with the EPA under the EPCRA and the federal Administrative Procedure Act to 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 Item 1A Risk Factors for more information. In addition, in August 2012, the SEC issued a final rule under Section 1504 of the Dodd-Frank Act, Disclosure of Payments by Resource Extraction Issuers, which would have required resource extraction issuers, such as QEP, to file annual reports that provide information about the type and total amount of payments made for each project related to the commercial development of oil, natural gas, or minerals to each foreign government and the federal government. In July 2013, the United States District Court for the District of Columbia vacated the rule and the SEC did not appeal that decision. However, the SEC may propose new rules on this subject in the future.

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.

Other Regulations. QEP Field Services' construction and operation activities are subject to various local, state, federal and tribal rules and regulations. Most of these rules and regulations are administered by the Department of Transportation, the Occupational Safety and Health Administration, and the EPA.

Regulation of Transportation of Oil by Pipeline

The Interstate Commerce Act (ICA), as applied to liquids pipelines, requires that rates and terms of service be just and reasonable and non-discriminatory. Under the ICA, FERC regulates the rates and terms and conditions of service for interstate movements of oil, NGL and refined petroleum products.

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, from approximately December through March, QEP typically ceases completion activities on newly drilled wells due to adverse weather conditions. 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 35%, 37%, and 32%, in the aggregate, of QEP's revenues for the years ended December 31, 2013, 2012 and 2011, 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, 2013, Freepoint Commodities, LLC, accounted for 12% of the Company's total revenues. During the year ended December 31, 2012, Chevron U.S.A. Inc. and Enterprise Products Operating, L.P. accounted for 13% and 10%, respectively, of the Company's total revenues. During the year ended December 31, 2011, no customer accounted for 10% or more of QEP's total revenues.

Employees

At December 31, 2013, QEP had 1,001 employees compared to 936 employees at December 31, 2012. None of QEP's employees are represented by unions or covered by collective bargaining agreements.

Executive Officers of the Registrant

The name, age, period of service, title and business experience of each of QEP's executive officers as of January 31, 2014, are listed below:

Charles B. Stanley	55	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	55	Executive Vice President, Chief Financial Officer, and Treasurer (2010 to present). Chief Accounting Officer (November 2013 to present). 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	50	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	60	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).
Perry H. Richards	53	Senior Vice President – Field Services (2010 to present). Previous title with Questar: Vice President, Questar Gas Management (2005 to 2010).
Abigail L. Jones	53	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	44	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 Fiala	50	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 the officers were selected.

ITEM 1A. RISK FACTORS

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 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 a decline in such prices could adversely affect QEP's results, stock price and growth plans. Historically gas, oil and NGL prices have been volatile and will likely continue to be volatile in the future. U.S. natural gas prices in particular are significantly influenced by weather and weather forecasts. 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 and 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. Because a significant portion of QEP Energy's future production is gas, the Company's financial results are substantially more sensitive to changes in gas prices than to changes in oil prices.

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;
- changes in local, regional, national and global demand for gas, oil, NGL and related commodities;
- the activities of the Organization of Petroleum Exporting Countries;
- domestic and global economic conditions;

- regional price differences resulting from available pipeline transportation capacity or local demand;
- terrorist attacks on production or transportation assets;
- the level of imports of, and the price of, foreign 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;
- political developments and actions in the United States and in or affecting other producing countries, including conflicts in the Middle East, Africa, South America and Russia;
- weather conditions and weather forecasts;
- 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;
- storage levels of gas, oil, and NGL; and
- the quality of oil and gas produced.

Lower commodity prices may reduce the amount of gas, oil and NGL that QEP can produce economically. In addition, lower commodity prices may result in asset impairment charges from reductions in the carrying values of QEP's oil and gas properties or a reduction in the carrying value of goodwill. During the years ended December 31, 2013 and 2012, QEP recorded impairment charges of $1.2 million and $107.6 million, respectively, on its proven properties and $32.3 million and $25.4 million, respectively, on its unproven properties. QEP also recorded a $59.5 million impairment of goodwill in 2013. 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 a 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. Global economic growth drives demand for energy from all sources, including fossil fuels. A lower future economic growth rate is likely to result in 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.

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.

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 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 also 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 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.

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 gathering, transporting, storage, processing and treating of natural gas; the fractionation, transportation and storage of NGLs; and oil transportation and production handling; including:

- injuries and/or deaths of employees, supplier personnel, or other individuals;
- fire, explosions and blowouts;
- aging infrastructure and mechanical problems;
- unexpected drilling conditions such as abnormally pressured formations;
- pipe, cement or casing failures;
- title problems;
- equipment malfunctions and/or mechanical failure on high-volume wells;
- security breaches, cyber attacks, 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, including from hydraulic fracturing activities.

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.

The location of pipelines near populated areas, including residential areas, commercial business centers and industrial sites could increase the level of damages resulting from these risks. Certain segments of QEP's pipelines run through such areas. In spite of QEP's precautions, an accident or other event could cause considerable harm to people or property, and could have a material adverse effect on QEP's financial position and results of operations, particularly if the event is not fully covered by insurance. Accidents or other operating risks once realized could further result in lost business. Such circumstances could adversely impact QEP's ability to meet contractual obligations.

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 as well as for claims for personal injury or death suffered by QEP's employees and others. QEP's drilling contracts and oilfield service agreements, however, generally 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.

Lack of availability of refining or transportation capacity could impact results of operations. The lack of availability of satisfactory oil, gas and NGL transportation, including trucks, railways and pipelines, 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 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 facilities do not exist near producing wells, if transportation 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. For example, during the third quarter of 2013, growing volumes on third-party gathering systems in QEP’s South Antelope area of the Williston Basin resulted in problems with the redelivery of oil from gathering systems to downstream markets. As a result, QEP was forced to take oil off the gathering system and truck it to rail-loading facilities, which delayed QEP’s operations and, as a result of additional trucking costs, reduced QEP’s realized prices. In addition, there have been rail accidents involving crude oil carriers, which may result in new restrictions on transportation of oil by railway. Furthermore, if QEP were required to shut in wells, it might also be obligated to pay 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. 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.

QEP acts as the general partner of a publicly traded master limited partnership, QEP Midstream, which may involve a greater exposure to legal liability than QEP’s historic business operations. One of QEP's subsidiaries acts as the general partner of QEP Midstream, a publicly traded master limited partnership. QEP’s control of the general partner of QEP Midstream may increase the possibility of claims of breach of fiduciary duties including claims of conflicts of interest related to QEP Midstream. Any liability resulting from such claims could have a material adverse effect on QEP’s future business, financial condition, results of operations and cash flows.

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.

The fees charged by QEP to third parties under its gathering and processing agreements may not escalate sufficiently to cover increases in costs, or the agreements may not be renewed or may be suspended in some circumstances. QEP's costs may increase at a rate greater than the fees it charges to third parties for gathering, treating and processing services.

Furthermore, third parties may not renew their contracts with QEP. Additionally, some third parties' obligations under their agreements with QEP may be permanently or temporarily reduced due to certain events, some of which are beyond QEP's control, including force majeure events wherein the supply of either gas, oil or NGL are curtailed or cut off. Force majeure events include (but are not limited to): wars, acts of enemies, embargoes, import or export restrictions, strikes, lockouts, fires, storms, floods, earthquakes, acts of God, explosions and mechanical or physical failures of equipment affecting QEP's facilities or facilities of third parties. If the escalation of fees is insufficient to cover increased costs, if third parties do not renew or extend their contracts with QEP or if third parties suspend or terminate their contracts with QEP, the Company's financial results would suffer.

QEP is required to pay fees to its 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, 2013, QEP's long-term contractual obligation under these agreements was $790.3 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 financings 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 or construction of new oil and gas processing facilities, 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 $3.0 billion at December 31, 2013. 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 agreements governing QEP's revolving credit facility, term loan 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 parties. 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, gathering or processing 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;
- cyber attacks;
- legal challenges or lawsuits;
- negative publicity about QEP;
- increased costs of doing business;
- reduction in demand for QEP's products; and
- other adverse effects on QEP's ability to develop its properties and increase production.

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 margining 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 credit-worthy 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.

Relative changes in NGL and gas prices may adversely impact QEP's results due to changes in the frac spread. Approximately 18%, 23% and 30% of QEP Field Services' net operating revenues for the years ended December 31, 2013, 2012 and 2011, respectively, were derived from keep-whole processing agreements. Under QEP's keep-whole processing contracts, QEP is exposed to the frac spread and transportation and fractionation exposure from firm transportation constraints. Generally, the frac spread and, consequently, the net operating margins are positive under these contracts. In the event gas becomes more expensive on a Btu equivalent basis than NGL products, QEP's cost of keeping the producer "whole" would result in operating losses. Due to timing of gas purchases and liquid sales, direct exposure to changes in market prices of either gas or liquids can be created, because there is an offsetting purchase or sale that remains exposed to market pricing. Through QEP's marketing and derivatives activity, direct exposure may occur naturally or QEP may choose direct price exposure to either gas or liquids when QEP favors that exposure over frac spread risk. Given that QEP has derivative positions, adverse movement in prices to the positions QEP has taken will negatively impact results.

QEP has made significant investments in new cryogenic gas processing plants in its Northern Region (Rockies) in recent years. The expected returns on these investments depend in large part on the future ethane price and margin, which historically have been more volatile than the price of other NGL products, including propane, butane and gasoline. QEP's competitors have also made significant investments in gas processing plants that recover significant volumes of ethane. The U.S. ethane market is currently oversupplied, and probably will remain oversupplied in the foreseeable future, resulting in lower ethane prices.

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 acquisition in the Williston Basin 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 such as QEP's current plans to sell non-core E&P assets located in the Midcontinent during 2014. 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.

The potential separation of QEP’s midstream business may not achieve its intended results. In December 2013, QEP announced its intention to pursue a separation of its midstream business. QEP may not be successful in consummating such a transaction. If QEP does consummate the separation of its midstream business, the separation may not achieve its intended results and could have an adverse effect on QEP due to a number of factors. For example, the separation may significantly reduce the scope and scale of QEP’s business, QEP may not be able to grow as expected and QEP may incur proportionately higher costs to operate.

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.

Current federal regulations restrict activities during certain times of the year on significant portions of QEP Energy leasehold in the Northern Region 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. Various wildlife species inhabit QEP Energy's leaseholds at Pinedale and in other areas. The presence of wildlife or plants, including species that are protected under the federal Endangered Species Act, could limit access to leases held by QEP Energy on public and other lands. 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 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 defined in the PAPA. The ROD contains additional requirements and restrictions on development of the PAPA to which QEP Energy is subject.

New federal Clean Air Act regulations at 40 CFR Part 63, Subpart OOOO impose additional air quality controls and requirements upon QEP Energy’s and QEP Field Services’ operations, and are undergoing further reconsideration by EPA. 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.

Several of QEP Field Services' transportation facilities are subject to FERC jurisdiction, and as such, are subject to specific regulations regarding interstate transmission facilities and activities, including but not limited to rates charged for transmission, open access/non-discrimination rules, and public daily capacity and flow reporting requirements. Additionally, 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.

Section 1(b) of the Natural Gas Act exempts gathering activities from regulation or jurisdiction by the FERC. QEP owns, or holds interests in, a number of pipelines that it believes meet the tests FERC has used to determine a pipeline system's status as a non-jurisdictional gatherer. There is, however, no bright-line test for determining jurisdictional status of QEP Field Services' gathering systems, so the distinction between non-jurisdictional gathering and FERC-regulated transmission pipelines may from time-to-time be the subject of disputes and litigation. QEP Field Services therefore cannot guarantee that the jurisdictional status of its gathering systems will remain unchanged. QEP's gas gathering systems are not currently subject to state utility regulations. The FERC has jurisdiction under the Energy Policy Act of 2005 to impose rules and regulations applicable to all natural gas market participants to ensure market transparency.

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 2014 Budget Proposal includes provisions 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 (i) the repeal of the percentage depletion allowance for oil and gas wells, (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 this legislation 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 increase the cost of exploration and development of oil and gas resources.

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 and midstream field services operations. 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, 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. The EPA recently asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuel under the federal SDWA and has begun the process of drafting guidance documents 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 Bureau of Land Management 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.

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. Additionally, the EPA and authorized states have begun the permitting of major sources of GHG under the Clean Air Act pursuant to the EPA's GHG Tailoring Rule whereby new and existing sources of GHG emitting above major source thresholds are required to obtain major source permits. In addition, several of the states in which QEP operates are considering various GHG registration and reduction programs, including methane leak detection monitoring and repair requirements specific to upstream and midstream oil and gas operations. While additional climate-change regulation is possible at the federal level, it is too early to predict how such regulation would affect QEP's business, operations or financial results. 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), enacted in July 2010, provides for federal oversight of the over-the-counter derivatives market and entities that participate in that market. The Dodd-Frank Act mandates that the Commodity Futures Trading Commission (CFTC), adopt rules and regulations implementing the Dodd-Frank Act and further defining certain terms used in the Dodd-Frank Act. The Dodd-Frank Act also requires the CFTC and the prudential banking regulators to establish margin requirements for certain uncleared swaps. Although there is an exception from swap clearing and trade execution requirements for commercial end-users that meet certain conditions (the End-User Exception), certain market participants, including most if not all of QEP’s counterparties, will also be required to clear many of their swap transactions with entities that do not satisfy the End-User Exception and will have to transact many of their swaps on swap execution facilities or designated contract markets, rather than over-the-counter on a bilateral basis. These requirements may increase the cost to QEP’s counterparties of hedging the swap positions they enter into with us, and thus may increase the cost to

QEP of entering into hedges. The changes in the regulation of swaps may result in certain market participants deciding to curtail or cease their derivatives activities. While many regulations have been promulgated and are already in effect, 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.

QEP qualifies as a "non-financial entity" for purposes of the End-User Exception and will seek to satisfy the other requirements of the End-User Exception on an ongoing basis. As a result, QEP does not expect its hedging activity to be subject to mandatory clearing.

A rule adopted under the Dodd-Frank Act imposing position limits in respect of transactions involving certain commodities, including oil and gas, was vacated and remanded to the CFTC for further proceedings by order of the United States District Court for the District of Columbia on September 28, 2012. The CFTC appealed this decision and on November 5, 2013, filed a consensual motion to dismiss its appeal. The same day, the CFTC proposed a new position limits rule which would limit trading in certain oil and gas related derivative contracts. Comments on the proposed rule are due February 10, 2014. QEP cannot predict whether or when the proposed rule will be adopted or the effect of the proposed rule on QEP's business. 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 credit-worthy 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 regulations is to lower commodity prices. Any of these consequences 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 128, or 13%, of QEP's active employees and 86 participants that are retired, terminated and vested, or suspended. 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, 2013 and 2012, QEP's pension plans were underfunded by $46.3 million and $74.4 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 $11.5 million and $6.9 million during the years ended December 31, 2013 and 2012, respectively, to its defined benefit pension plans and expects to make contributions of approximately $13.8 million to its pension plans in 2014. 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.

A failure in QEP’s information technology infrastructure or applications could negatively affect QEP’s business.

QEP is planning to have a new enterprise resource planning (ERP) system to further enhance operating efficiencies and provide more effective management of its business operations in 2014. Implementing a new ERP system is costly and involves risks inherent in the conversion to a new computer system, including loss of information, disruption to QEP’s normal operations, changes in accounting procedures and internal control over financial reporting, as well as problems achieving accuracy in the conversion of electronic data. Failure to properly or adequately address these issues could result in increased costs and the diversion of management’s and employees’ attention and resources and could materially adversely affect QEP’s operating results, internal controls over financial reporting and ability to manage its business effectively. While the ERP system is intended to further improve and enhance QEP’s information systems, large scale implementation of a new information system exposes QEP to the risks of starting up the new system and integrating that system with QEP’s existing systems and processes, including possible disruption of QEP’s financial reporting, which could lead to a failure to make required filings under the federal securities laws on a timely basis.

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 and processing 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. QEP's technologies, systems, networks, and those of its vendors, suppliers and other business partners may become the target of cyber attacks 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.

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, Utah, Colorado and North Dakota) and the Southern Region (including the states of Oklahoma, Texas and Louisiana).

Northern Region

Pinedale

QEP's largest property, in terms of proved reserves, is Pinedale, where the Company is targeting the Lance Pool 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 over 600 additional wells required to fully develop its Pinedale acreage on 5 to 10-acre density. At December 31, 2013, QEP Energy had four operated rigs drilling in the Pinedale Anticline. In addition to QEP Energy's 798 gross producing wells, QEP Energy has an overriding royalty interest in an additional 50 wells at Pinedale.

Williston Basin
QEP has approximately 116,000 net acres of leaseholds in the Williston Basin in western North Dakota, where the Company is targeting the Bakken and Three Forks formations. During the third quarter of 2012, QEP Energy closed the acquisition of oil and gas properties in the Williston Basin (the 2012 Acquisition), which added 27,600 net acres of producing leasehold. 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, 2013, QEP Energy had eight operated rigs drilling in the Williston Basin.

Since the 2012 Acquisition, the Company has been successful in lowering development well costs, de-risking unproven reserves, and increasing production, the number of future drilling locations and its estimate of recoverable reserves. In spite of completion delays due to downstream and weather-related issues, current Williston Basin oil production has grown to levels consistent with the Company's expectations at the time of the acquisition.

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 257,000 net leasehold acres in the Uinta Basin. QEP Energy had one operated rig drilling in the Uinta Basin at December 31, 2013, targeting the Lower Mesaverde Formation productive fairway in the Red Wash Unit, in which QEP holds 32,300 net acres.

Legacy
The remainder of QEP Energy Northern Region leasehold interests, productive wells and proved reserves are distributed over a number of fields and properties managed as Legacy.

Southern Region

Haynesville/Cotton Valley
QEP Energy has approximately 50,500 net acres of Haynesville Shale leaseholds in northwest 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 below the Hosston and Cotton Valley formations that QEP Energy has been developing in northwest Louisiana since the 1990's. As of December 31, 2013, QEP Energy did not have any operated rigs drilling in the Haynesville/Cotton Valley area.

Midcontinent
QEP Energy's Midcontinent operations cover all properties in the Southern Region except the Haynesville/Cotton Valley area of northwest Louisiana and are distributed over a large area, including the Anadarko Basin of Oklahoma and the Texas Panhandle.

QEP Energy has approximately 76,000 net acres of Woodford "Cana" Shale leaseholds in western Oklahoma. The top of the Woodford Shale ranges from approximately 10,500 feet to 14,500 feet across QEP Energy's leasehold. As of December 31, 2013, QEP Energy had two operated rigs drilling in the Woodford/Cana play.

QEP Energy has approximately 35,000 net acres of Granite Wash/Atoka Wash leaseholds in the Texas Panhandle and western Oklahoma and has been drilling vertical Granite Wash/Atoka Wash wells for over a decade. The top of the Granite Wash/Atoka Wash interval ranges from approximately 11,100 feet to 15,900 feet across QEP Energy's leasehold. As of December 31, 2013, QEP Energy did not have any operated rigs drilling in the Texas Panhandle.

Reserves – QEP Energy

At December 31, 2013 and 2012, approximately 89% and 91%, respectively, of QEP Energy's estimated proved reserves were Company operated. Proved developed reserves represented 53% and 54% of the Company's total proved reserves at December 31, 2013 and 2012, 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, 2013				December 31, 2012			
	Gas	Oil	NGL	Total	Gas	Oil	NGL	Total
	(Bcf)	(MMbbl)	(MMbbl)	(Bcfe)[1]	(Bcf)	(MMbbl)	(MMbbl)	(Bcfe)[1]
Proved developed reserves	**1,406.3**	**71.8**	**52.8**	**2,154.0**	1,531.7	47.4	49.3	2,111.9
Proved undeveloped reserves	**1,148.6**	**76.8**	**49.8**	**1,907.9**	1,090.7	71.6	50.6	1,824.2
Total proved reserves	**2,554.9**	**148.6**	**102.6**	**4,061.9**	2,622.4	119.0	99.9	3,936.1

(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, 2011, through December 31, 2013, 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)
2011	3,613.8	275.2	13.1
2012	3,936.1	319.2	12.3
2013	**4,061.9**	**309.0**	**13.1**

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

Proved Reserves
Reserve and related information is presented consistent with the requirements of the SEC's rules for the Modernization of Oil and Gas Reporting. These rules expand the use of reliable technologies to estimate and categorize reserves and require the use of the average of the first-of-the-month commodity prices, adjusted for location and quality differentials, for the prior 12 months (unless contractual arrangements designate the price) used 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 17 - Supplemental Oil and Gas Information (Unaudited), in Item 8 of Part II of this Annual Report 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,			
	2013		2012	
Northern Region	**(Bcfe)**	**(% of total)**	(Bcfe)	(% of total)
Pinedale	**1,563.2**	**39%**	1,530.8	39%
Williston Basin	**797.5**	**20%**	614.7	16%
Uinta Basin	**586.4**	**14%**	617.9	16%
Legacy	**92.6**	**2%**	112.2	3%
Southern Region				
Haynesville/Cotton Valley	**502.8**	**12%**	530.5	13%
Midcontinent	**519.4**	**13%**	530.0	13%
Total QEP Energy	**4,061.9**	**100%**	3,936.1	100%

Estimates of the quantity of proved reserves increased during 2013 primarily related to reserve additions in the Williston Basin, offset by decreases in estimated Haynesville/Cotton Valley and Legacy proved reserves. The increase in Williston Basin reserves was primarily the result of extensions and additions from the recognition of additional proved undeveloped locations due to QEP's increased drilling program. The Haynesville/Cotton Valley decrease was primarily related to changes in performance estimates based on well performance during 2013 as well as the natural decline in reserves from production without reserve replacement from the lack of new wells being drilled. Legacy's proved reserves decreased as a result of property divestitures in 2013.

Proved Undeveloped Reserves

Significant changes to proved undeveloped reserves (PUDs) that occurred during 2013 are summarized in the table below:

	2013
	(Bcfe)
Proved undeveloped reserves at January 1,	**1,824.2**
Transferred to proved developed reserves	**(332.7)**
Revisions to previous estimates [1]	**(271.3)**
Extensions and discoveries [2]	**687.7**
Proved undeveloped reserves at December 31, [3]	**1,907.9**

(1) Negative revisions were caused by a change in well spacing assumptions in Pinedale and Haynesville. Some more densely spaced wells were removed from the Company's reserves. However, certain less densely spaced wells with higher estimates of recoverable oil and gas were rebooked as extensions and discoveries. Negative revisions were also partially offset by positive pricing-related revisions due to increased oil and gas prices during 2013.

(2) Extensions and discoveries in 2013 increased proved undeveloped reserves due to extensions and discoveries of 263.9 Bcfe in Pinedale, 169.6 Bcfe in the Williston Basin, 170.3 Bcfe in Haynesville, and 83.9 Bcfe in Midcontinent. Extensions and discoveries in Pinedale and Haynesville related to certain less densely spaced wells with higher estimates of recoverable oil and gas, which were rebooked to replace wells removed from the Company's reserves through negative revisions caused by a change in well spacing assumptions in these areas.

(3) All of QEP Energy's PUDs at December 31, 2013, are scheduled to be developed within five years from the date such locations were initially booked as PUDs, except for 120 Bcfe of reserves located within the northern portion of the Company's Pinedale Anticline leasehold in western Wyoming. 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 require 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.

The costs incurred to continue the development of PUDs were approximately $645.9 million, $513.0 million and $533.6 million for the years ended December 31, 2013, 2012 and 2011, respectively. The costs incurred in 2013 related to the drilling of PUDs in QEP's development projects. This investment resulted in the transfer in 2013 of 332.7 Bcfe of reserves from PUDs to proved developed reserves, representing 18% of the Company's total proved undeveloped reserves as of December 31, 2012.

Estimated future development costs relating to the development of PUDs are projected to be approximately $852.6 million in 2014, $1.2 billion in 2015, and $1.1 billion in 2016. Estimated future development costs include capital spending on major development projects, some of which will take several years to complete. PUDs 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, independent oil and gas reserve evaluation engineering consultants (Ryder Scott), to prepare the estimates of 100% of its proved reserves as of December 31, 2013, 2012 and 2011. The individual at Ryder Scott who was responsible for overseeing the preparation of QEP's reserve estimates as of December 31, 2013, 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 experience in the Petroleum Industry, including experience estimating and evaluating petroleum reserves. A more detailed letter of the individual's professional qualifications has been filed as part of Exhibit 99.1 to this report.

The individual at QEP responsible for insuring the accuracy of the reserve estimate preparation material provided to Ryder Scott and reviewing the estimates of reserves received from Ryder Scott 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 Geological Engineering from South Dakota School of Mines and Technology in 1979. He is a registered Professional Petroleum Engineer in the state of

Colorado. This individual has over 30 years experience in the Petroleum Industry, including more than 20 years reservoir engineering experience in most of the active domestic basins in the U.S.

To establish 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 2013 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 99% 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 one percent of such reserves was estimated by the volumetric method. The volumetric analysis utilized pertinent well data furnished to Ryder Scott by QEP or obtained from available public data sources through December 2013. 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, producing 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 17 - 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 reserves estimates as of December 31, 2013, with the Energy Information Administration of the Department of Energy on Form EIA-23. Although QEP uses the same technical and economic assumptions when it prepares the EIA-23 as used to estimate reserves for this Annual Report on Form 10-K, it is obligated to report 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, 2013, 2012 and 2011:

	Year Ended December 31,		
	2013	2012	2011
QEP Energy			
Volumes produced and sold			
Gas (Bcf)	**218.9**	249.3	236.4
Oil (Mbbl)	**10,209.7**	6,306.9	3,741.3
NGL (Mbbl)	**4,811.3**	5,349.0	2,715.6
Total equivalent production (Bcfe)	**309.0**	319.2	275.2
Average field-level price [(1)]			
Gas (per Mcf)	**$ 3.56**	$ 2.68	$ 3.95
Oil (per bbl)	**89.78**	84.45	86.20
NGL (per bbl)	**39.95**	34.43	47.76
Lifting costs (per Mcfe)			
Lease operating expense	**$ 0.59**	$ 0.55	$ 0.54
Production taxes	**0.51**	0.30	0.36
Total lifting costs	**$ 1.10**	$ 0.85	$ 0.90

(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	
	2013	2012	2011	**2013 vs 2012**	2012 vs 2011
QEP Energy - Gas (Bcf)					
Northern Region					
Pinedale	**80.0**	77.4	69.3	**2.6**	8.1
Williston Basin	**2.7**	0.9	0.1	**1.8**	0.8
Uinta Basin	**18.6**	16.3	14.9	**2.3**	1.4
Legacy	**10.3**	11.4	12.1	**(1.1)**	(0.7)
Southern Region					
Haynesville/Cotton Valley	**71.8**	112.0	107.1	**(40.2)**	4.9
Midcontinent	**35.5**	31.3	32.9	**4.2**	(1.6)
Total production	**218.9**	249.3	236.4	**(30.4)**	12.9

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

	Year ended December 31,			Change	
	2013	2012	2011	**2013 vs 2012**	2012 vs 2011
QEP Energy - Oil (Mbbl)					
Northern Region					
Pinedale	**657.6**	664.4	583.8	**(6.8)**	80.6
Williston Basin	**7,026.2**	3,029.5	1,133.5	**3,996.7**	1,896.0
Uinta Basin	**924.9**	890.9	866.7	**34.0**	24.2
Legacy	**237.7**	297.6	271.0	**(59.9)**	26.6
Southern Region					
Haynesville/Cotton Valley	**43.2**	43.4	51.0	**(0.2)**	(7.6)
Midcontinent	**1,320.1**	1,381.1	835.3	**(61.0)**	545.8
Total production	**10,209.7**	6,306.9	3,741.3	**3,902.8**	2,565.6

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

	Year ended December 31,			Change	
	2013	2012	2011	**2013 vs 2012**	2012 vs 2011
QEP Energy - NGL (Mbbl)					
Northern Region					
Pinedale	**1,787.5**	3,054.3	1,099.6	**(1,266.8)**	1,954.7
Williston Basin	**390.0**	197.1	29.5	**192.9**	167.6
Uinta Basin	**463.8**	371.1	106.4	**92.7**	264.7
Legacy	**36.7**	100.1	100.5	**(63.4)**	(0.4)
Southern Region					
Haynesville/Cotton Valley	**21.3**	8.5	8.4	**12.8**	0.1
Midcontinent	**2,112.0**	1,617.9	1,371.2	**494.1**	246.7
Total production	**4,811.3**	5,349.0	2,715.6	**(537.7)**	2,633.4

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

	Year ended December 31,			Change	
	2013	2012	2011	**2013 vs 2012**	2012 vs 2011
QEP Energy - Total Production (Bcfe)					
Northern Region					
Pinedale	**94.7**	99.7	79.4	**(5.0)**	20.3
Williston Basin	**47.2**	20.3	7.1	**26.9**	13.2
Uinta Basin	**26.9**	23.9	20.8	**3.0**	3.1
Legacy	**11.9**	13.7	14.2	**(1.8)**	(0.5)
Southern Region					
Haynesville/Cotton Valley	**72.2**	112.3	107.5	**(40.1)**	4.8
Midcontinent	**56.1**	49.3	46.2	**6.8**	3.1
Total production	**309.0**	319.2	275.2	**(10.2)**	44.0

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

	Year Ended December 31,			Change	
	2013	2012	2011	**2013 vs 2012**	2012 vs 2011
QEP Energy - Average field-level gas price (per Mcf)					
Northern Region	**$ 3.58**	$ 2.64	$ 3.87	**$ 0.94**	$ (1.23)
Southern Region	**3.54**	2.70	4.00	**0.84**	(1.30)
Average field-level gas price	**3.56**	2.68	3.95	**0.88**	(1.27)
QEP Energy - Average field-level oil price (per bbl)					
Northern Region	**$ 89.35**	$ 83.03	$ 84.88	**$ 6.32**	$ (1.85)
Southern Region	**92.60**	89.32	90.45	**3.28**	(1.13)
Average field-level oil price	**89.78**	84.45	86.20	**5.33**	(1.75)
QEP Energy - Average field-level NGL price (per bbl)					
Northern Region	**$ 46.56**	$ 36.17	$ 52.00	**$ 10.39**	$ (15.83)
Southern Region	**31.65**	30.44	43.66	**1.21**	(13.22)
Average field-level NGL price	**39.95**	34.43	47.76	**5.52**	(13.33)

Northern Region

Pinedale

Production from the Pinedale Anticline 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 operating in ethane rejection mode throughout the majority of 2013 compared to operating in ethane recovery throughout the majority of 2012. Additionally, QEP had lower average interest in wells drilled in the 2013 drilling program.

Production from Pinedale grew 26% to 99.7 Bcfe during 2012 compared to 2011, driven by increased drilling activity over the period and the fee-based processing agreement at Blacks Fork II entered into in the third quarter of 2011 between QEP Energy and QEP Field Services.

During the years ended December 31, 2013, 2012 and 2011, Pinedale's production represented 31%, 31%, and 29% of QEP Energy's total production, respectively.

Williston Basin

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

During 2012, production increased 186% compared to 2011, due to increased oil-directed drilling activity in the basin. In addition, the 2012 Acquisition contributed 5.2 Bcfe of increased production in the fourth quarter 2012.

During the years ended December 31, 2013, 2012 and 2011, Williston Basin production represented 15%, 6%, and 3% of QEP Energy's total production, respectively.

Uinta Basin

In the Uinta Basin, production increased 13% to 26.9 Bcfe during 2013, due to increased drilling activity in the Lower Mesaverde formation in the Red Wash Unit. NGL production increased 92.7 Mbbl 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 production related to processing plants running in ethane rejection mode throughout the majority of 2013.

During 2012, production increased 15% due to increased drilling activity in the Lower Mesaverde formation in the Red Wash Unit. NGL production increased 264.7 Mbbl during 2012 compared to 2011, 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.

During the years ended December 31, 2013, 2012 and 2011, Uinta Basin production represented 9%, 7%, and 8%, respectively, of QEP Energy's total production.

Legacy
QEP Energy's Legacy's production decreased 13% to 11.9 Bcfe during 2013 compared to 2012, due to declining production on older wells and divestitures of certain of QEP's noncore properties in the Northern Region during 2013.

Legacy's production decreased 4% to 13.7 Bcfe during the year ended December 31, 2012 compared to 2011, due to declining production on older wells partially offset by increased drilling activity in the Powder River Basin during 2012.

During the years ended December 31, 2013, 2012 and 2011, Legacy's production represented 4% of QEP Energy's total production.

Southern Region

Haynesville/Cotton Valley
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 oil rich areas during 2013.

Production from the Haynesville Shale and Cotton Valley increased 4% to 112.3 Bcfe during 2012 when compared to 2011. The increase in 2012 was due to the completion of several high-rate wells in early 2012 that were drilled during the latter half of 2011.

During the years ended December 31, 2013, 2012 and 2011, Haynesville/Cotton Valley's production comprised 23%, 35%, and 39% of QEP Energy's total production, respectively.

Midcontinent
Production in the Midcontinent grew 14% to 56.1 Bcfe during 2013 when compared to 2012, due to 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.

Net production in the Midcontinent grew 7% to 49.3 Bcfe during 2012 compared to 2011, driven by a 65% increase in oil production and an 18% increase in NGL production driven by the continued development of the Granite Wash, Marmaton and Tonkawa plays in Texas and western Oklahoma and the Woodford "Cana" Shale liquids-rich gas play in the Anadarko Basin of western Oklahoma.

During the years ended December 31, 2013, 2012 and 2011, Midcontinent's production represented 18%, 15%, and 17% of QEP Energy's total production, respectively.

Productive Wells
The following table summarizes the Company's productive wells as of December 31, 2013, all of which are located in the U.S.:

	Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Northern Region						
Pinedale	798	512	—	—	798	512
Williston Basin	—	—	452	154	452	154
Uinta Basin	687	501	1,645	240	2,332	741
Legacy	590	196	94	17	684	213
Southern Region						
Haynesville/Cotton Valley	779	449	1	—	780	449
Midcontinent	2,392	747	377	83	2,769	830
Total productive wells	5,246	2,405	2,569	494	7,815	2,899

The term "gross" refers to all wells or acreage in which QEP has at least 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, 2013. "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	155,497	105,491	98,712	28,022	254,209	133,513
Montana	15,110	7,293	303,385	52,260	318,495	59,553
New Mexico	162,467	43,874	195,649	80,538	358,116	124,412
North Dakota	38,730	31,748	22,351	2,346	61,081	34,094
South Dakota	—	—	204,398	107,151	204,398	107,151
Wyoming	186,318	149,056	204,107	126,328	390,425	275,384
Utah	224,487	141,465	293,216	205,838	517,703	347,303
Other	2,995	1,215	156,523	42,010	159,518	43,225
Southern Region					—	—
Arkansas	33,733	10,055	1,387	931	35,120	10,986
Kansas	29,474	12,658	51,259	17,264	80,733	29,922
Louisiana	73,329	61,912	1,667	1,723	74,996	63,635
Oklahoma	529,182	242,227	361,746	101,821	890,928	344,048
Texas	77,355	36,205	4,146	1,887	81,501	38,092
Other	—	—	1,757	1,300	1,757	1,300
Total	**1,528,677**	**843,199**	**1,900,303**	**769,419**	**3,428,980**	**1,612,618**

(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,		
2014	52,961	38,909
2015	91,882	71,714
2016	31,829	30,262
2017	58,429	55,156
2018 and later	36,471	35,085
Total	271,572	231,126

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, 2013								
Northern Region								
Pinedale	**111.0**	**61.5**	—	—	—	—	—	—
Williston Basin	**176.0**	**70.7**	—	—	—	—	—	—
Uinta Basin	**224.0**	**39.4**	—	—	—	—	—	—
Legacy	**6.0**	**0.2**	—	—	**1.0**	**1.0**	—	—
Southern Region								
Haynesville/Cotton Valley	**11.0**	**3.4**	—	—	—	—	—	—
Midcontinent	**135.0**	**29.3**	—	—	—	—	—	—
Total	**663.0**	**204.5**	—	—	**1.0**	**1.0**	—	—
Year Ended December 31, 2012								
Northern Region								
Pinedale	102.0	73.3	—	—	—	—	—	—
Williston Basin	88.0	28.0	—	—	—	—	—	—
Uinta Basin	254.0	45.1	—	—	1.0	0.6	—	—
Legacy	31.0	6.6	—	—	—	—	—	—
Southern Region								
Haynesville/Cotton Valley	35.0	15.7	—	—	2.0	1.6	—	—
Midcontinent	157.0	32.2	—	—	—	—	—	—
Total	667.0	200.9	—	—	3.0	2.2	—	—
Year Ended December 31, 2011								
Northern Region								
Pinedale	105.0	71.6	—	—	—	—	—	—
Uinta Basin	176.0	6.3	—	—	—	—	—	—
Legacy [(1)]	85.0	22.5	—	—	—	—	—	—
Southern Region								
Haynesville/Cotton Valley	91.0	36.7	—	—	6.0	1.7	2.0	0.7
Midcontinent	221.0	39.6	—	—	—	—	4.0	1.9
Total	678.0	176.7	—	—	6.0	1.7	6.0	2.6

(1) Following the 2012 Acquisition, the Company began reporting the results of Williston Basin separately from Legacy in 2012. The Legacy well totals for the year ended December 31, 2011, include the total development and exploratory wells drilled in the Williston Basin.

The following table presents operated and non-operated well completions for the year ended December 31, 2013:

	Operated Completions		Non-operated Completions	
	Gross	Net	Gross	Net
Northern Region				
Pinedale	111	61.5	—	—
Williston Basin	74	65.6	102	5.1
Uinta Basin	42	39.0	182	0.4
Legacy	—	—	7	1.2
Southern Region				
Haynesville/Cotton Valley	5	2.4	6	1.0
Midcontinent	24	19.1	111	10.2

The following table presents operated and non-operated wells drilling and waiting on completion at December 31, 2013:

	Operated				Non-operated			
	Drilling		Waiting on completion		Drilling		Waiting on completion	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Northern Region								
Pinedale [(1)]	18	14.2	54	42.4	—	—	—	—
Williston Basin	26	21.6	8	7.5	31	3.2	5	0.3
Uinta Basin	1	1.0	—	—	—	—	—	—
Legacy	—	—	—	—	—	—	—	—
Southern Region								
Haynesville/Cotton Valley	—	—	—	—	3	0.1	16	0.4
Midcontinent	1	1.0	1	0.9	4	0.1	47	3.1

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

QEP 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 63 gross operated wells waiting on completion as of December 31, 2013.

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:

	Delivery Commitments
Period	(millions of MMBtu)
2014	18.7
2015	1.4
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 Item 7 "Contractual Cash Obligations and Other Commitments" 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 Item 1A - Risk Factors, in this Annual Report on Form 10-K.

Midstream Field Services – QEP Field Services

QEP Field Services provides midstream services (gathering, processing and treating) to QEP Energy and third-party customers, including major and independent producers. QEP Field Services' physical assets include the following:

- 810 miles of gathering lines in Utah and Louisiana;
- six processing plants, which extract NGL from the natural gas stream and have an aggregate capacity of 1.52 Bcf per day of unprocessed natural gas;
- treating facilities in northwest Louisiana which remove impurities from the natural gas stream and have an aggregate capacity of 600 MMcf per day of untreated natural gas;
- compression facilities and field dehydration and measurement systems; and
- the UBFS system, which consists of 100 miles of gathering lines and associated field equipment.

In February 2013, QEP Field Services put into service the 150 MMcf per day Iron Horse II cryogenic processing plant, an expansion of its Stagecoach and Iron Horse processing complex in the Uinta Basin of eastern Utah. The plant predominantly provides fee-based processing services to third parties and affiliates. During the third quarter of 2013, QEP Field Services completed the 10,000 Bbl per day expansion of the NGL fractionation facility located at the Blacks Fork processing complex.

QEP Field Services also owns a majority interest in QEP Midstream, a publicly traded master limited partnership that was formed by QEP to own, operate, acquire and develop midstream energy assets. QEP Midstream was formed in 2013 and completed its initial public offering in August 2013. In connection with the IPO, QEP Field Services contributed certain assets to QEP Midstream in exchange for net proceeds of $351.1 million and a 57.8% interest in QEP Midstream. QEP Midstream's assets currently consist of the following:

- Four gathering systems consisting of 1,129 miles of gathering lines in Wyoming, Colorado, Utah and North Dakota;
- Rendezvous Pipeline, a FERC regulated 21-mile, 20-inch diameter pipeline that can deliver up to 460 MMcf of natural gas per day to the Kern River Pipeline;
- a 78% interest in Rendezvous Gas, a joint venture consisting of 310 miles of gathering lines and associated field equipment; and
- a 50% interest in Three Rivers Gathering, a joint venture that consists of 52 miles of gathering lines and associated field equipment.

Delivery Commitments
The Company sells NGL under a term sales agreement that contains a delivery commitment for 8,500 barrels per day of NGL extracted at several of QEP Field Services' gas processing facilities in the Northern Region. The agreement, which became effective May 1, 2010, extends for a period of seven years and contains terms and conditions customary for an agreement of this type in the oil and gas industry. The Company believes that the reserves dedicated to gas processing facilities and projected processing volumes are adequate to satisfy its delivery commitments under this agreement.

Energy Marketing – QEP Marketing

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.

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:

	Delivery Commitments
Period	(millions of MMBtu)
2014	72.5
2015	31.4
2016	—
2017	0.3
2018	0.4
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 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 Item 7 "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 to the consolidated financial statements 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, 2014, QEP had 6,792 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 2013 and 2012:

	High price	Low price	Dividend
		(per share)	
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**
2012			
First quarter	$ 35.61	$ 26.73	$ 0.02
Second quarter	32.03	24.35	0.02
Third quarter	33.50	26.12	0.02
Fourth quarter	32.92	25.99	0.02
Total			$ 0.08

Stock Performance Graph

The following stock performance information in this Item 5 of this Annual Report on Form 10-K is not deemed to be "soliciting material" or to be "filed" with the SEC or subject to Regulation 14A or 14C under the Securities Exchange Act of 1934 or to the liabilities of Section 18 of the Securities Exchange Act of 1934, and will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent QEP specifically incorporates it by reference into such a filing.

During 2013, the Board of Directors made changes to QEP's peer group to remove EOG Resources due to dissimilar financial characteristics. In addition, Plains Exploration & Production was acquired in 2013 and therefore was removed from the peer group. WPX Energy Inc., Concho Resources, and SM Energy were added to QEP's peer group, which is comprised of US companies of similar size and scope to QEP.

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

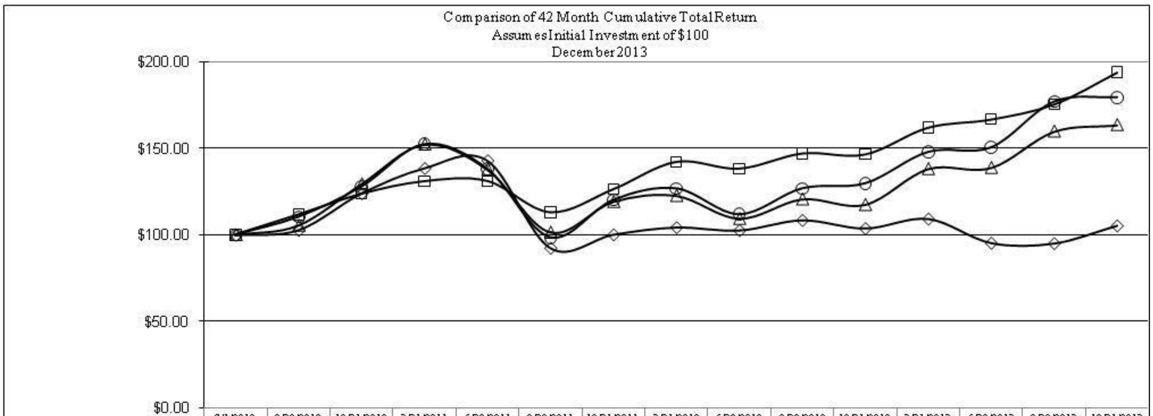
Cabot Oil & Gas Corporation	Pioneer Natural Resources Company
Cimarex Energy Company	Plains Exploration & Production Company
Denbury Resources Inc.	Quicksilver Resources, Inc.
EOG Resources, Inc.	Range Resources Corporation
Forest Oil Corporation	Southwestern Energy Company
Newfield Exploration Company	Ultra Petroleum Corporation
Noble Energy, Inc.	Whiting Petroleum Corporation

After the change in peer companies, the 2013 peer group consisted of the following:

Cabot Oil & Gas Corporation	Pioneer Natural Resources Company
Cimarex Energy Company	Range Resources Corporation
Concho Resources	SM Energy
Denbury Resources Inc.	Southwestern Energy Company
Forest Oil Corporation	Ultra Petroleum Corporation
Newfield Exploration Company	Whiting Petroleum Corporation
Noble Energy, Inc.	WPX Energy, Inc.
Quicksilver Resources, 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, the Company's old peer group and new 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 old and new 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.



	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
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
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
New 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
Old Peer Group	100.00	110.30	127.71	152.27	138.07	98.46	120.07	126.72	111.78	126.78	129.66	147.79	150.44	176.89	179.45

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

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

Period	Total shares purchased (1)	Weighted-average price paid per share	Total shares purchased as part of publicly announced plans or programs	Maximum number of shares that may yet be purchased under the plans or programs
October 1, 2013 - October 31, 2013	—	—	—	—
November 1, 2013 - November 30, 2013	—	—	—	—
December 1, 2013 - December 31, 2013	20,541	$ 30.80	—	—

(1) All of the 20,541 shares purchased during the three-month period ended December 31, 2013, were acquired from employees in connection with the settlement of income tax and related benefit withholding obligations arising from vesting in restricted stock grants. These shares were not part of a publicly announced program to purchase common stock. Stock options that are net settled do not involve the acquisition of any shares.

In January 2014, the Board of Directors of QEP authorized the repurchase of up to $500.0 million of the Company’s outstanding shares of common stock. 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.

ITEM 6. SELECTED FINANCIAL DATA

Selected financial data for the five years ended December 31, 2013, is provided in the table below. Refer to Item 7 and Item 8 in Part II of this Annual Report on Form 10-K for a discussion of the factors affecting the comparability of the Company's financial data.

	Year Ended December 31,				
	2013(1)	2012(2)	2011	2010	2009
	(in millions, except per share information)				
Results of Operations					
Revenues (4)	**$ 2,935.8**	$ 2,349.8	$ 3,159.2	$ 2,300.6	$ 2,011.2
Operating income (loss)	**384.6**	(133.3)	505.9	545.3	585.5
Income from continuing operations	**171.4**	132.0	270.4	285.9	215.4
Discontinued operations, net of income tax(3)	**—**	—	—	43.2	80.7
Net income attributable to QEP	**159.4**	128.3	267.2	326.2	293.5
Earnings per common share attributable to QEP					
Basic from continuing operations	**$ 0.89**	$ 0.72	$ 1.51	$ 1.61	$ 1.23
Basic from discontinued operations(3)	**—**	—	—	0.25	0.46
Basic total	**$ 0.89**	$ 0.72	$ 1.51	$ 1.86	$ 1.69
Diluted from continuing operations	**$ 0.89**	$ 0.72	$ 1.50	$ 1.60	$ 1.21
Diluted from discontinued operations	**—**	—	—	0.24	0.46
Diluted total	**$ 0.89**	$ 0.72	$ 1.50	$ 1.84	$ 1.67
Dividends per share	**$ 0.08**	$ 0.08	$ 0.08	$ 0.04	$ —
Weighted-average common shares outstanding					
Used in basic calculation	**179.2**	177.8	176.5	175.3	174.1
Used in diluted calculation	**179.5**	178.7	178.4	177.3	176.3
Financial Position					
Total Assets at December 31,	**$ 9,376.8**	9,108.5	$ 7,442.7	$ 6,785.3	$ 6,481.4
Capitalization at December 31,					
Long-term debt	**2,997.5**	3,206.9	1,679.4	1,530.8	1,348.7
Total equity	**3,876.8**	3,313.7	3,352.1	3,063.1	2,808.7
Total Capitalization	**$ 6,874.3**	6,520.6	$ 5,031.5	$ 4,593.9	$ 4,157.4
Cash Flow From Continuing Operations					
Net cash provided by operating activities	**$ 1,191.7**	$ 1,296.0	$ 1,292.6	$ 997.5	$ 1,149.4
Capital expenditures	**(1,602.6)**	(2,799.7)	(1,431.1)	(1,469.0)	(1,196.9)
Net cash used in investing activities	**(1,441.5)**	(2,794.5)	(1,422.9)	(1,390.5)	(1,146.4)
Net cash provided by (used in) financing activities	**261.7**	1,498.5	130.3	373.7	(8.8)
Non-GAAP Measures					
Adjusted EBITDA (5)	**$ 1,536.7** —	$ 1,409.0 115	$ 1,380.7	$ 1,134.9	$ 1,160.2

(1) During the year ended December 31, 2013, QEP completed the IPO of QEP Midstream. Prior to the IPO on August 14, 2013, QEP Midstream's assets were wholly owned by QEP Field Services. Subsequent to the IPO, QEP Midstream's results are consolidated with the portion not owned by QEP reflected as noncontrolling interest. Refer to Note 3 - QEP Midstream, in Part II, Item 8 of this Annual Report on Form 10-K for detailed information on the IPO.

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

(3) QEP completed a Spin-off from Questar in June 2010. 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 and all prior periods have been recast.

(4) Revenue for the years ended December 31, 2011, 2010 and 2009, reflect the impact of QEP's settled derivative contracts, which during the year ended December 31, 2013 and 2012, are reflected below operating (loss) income. See Note 7 - Derivative Contracts, in Part II, Item 8 of this Annual Report on Form 10-K for detailed information on derivative contract settlements in the years ended December 31, 2013, 2012 and 2011.

(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 of the Company's cash flow and liquidity and its ability to incur and service debt, fund capital expenditures and return capital to shareholders, and an important measure for comparing the Company's financial performance to other oil and gas producing companies.

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

	Year Ended December 31,						
	2013		2012		2011	2010	2009
	(in millions, except per share information)						
Adjusted EBITDA							
Net income attributable to QEP	**$ 159.4**		$ 128.3		$ 267.2	$ 326.2	$ 293.5
Discontinued operations, net of tax	**—**		—		—	(43.2)	(80.7)
Income from continuing operations	**159.4**		128.3		267.2	283.0	212.8
Unrealized (gains) losses on derivative contracts	**88.7**	**88.7**	(63.2)		(117.7)	(121.7)	164.0
Net gains from asset sales	**(103.0)**	**—**	(1.2)	—	(1.4)	(12.1)	(1.5)
Interest and other income	**(5.2)**	**—**	(6.6)	—	(4.1)	(2.3)	(4.5)
Income taxes	**119.8**	**—**	66.5	—	154.4	167.0	117.6
Interest expense[1]	**162.9**	**—**	122.9	—	90.0	84.4	70.1
Accrued litigation loss contingency [3]	**—**	**—**	115.0	—	—	—	—
Separation costs	**—**		—		—	13.5	—
Loss from early extinguishment of debt	**—**	**—**	0.6	—	0.7	13.3	—
Depreciation, depletion and amortization[2]	**1,009.2**		902.5		762.9	640.7	556.4
Impairment	**93.0**		133.0		218.2	46.1	20.3
Exploration expenses	**11.9**		11.2		10.5	23.0	25.0
Adjusted EBITDA	**$ 1,536.7**		$ 1,409.0		$ 1,380.7	$ 1,134.9	$ 1,160.2

(1) Excludes noncontrolling interest's share of $0.4 million during the year ended December 31, 2013, of interest expense attributable to QEP Midstream.

(2) Excludes noncontrolling interests' share of $6.8 million, $2.8 million, $2.7 million, $2.7 million and $2.7 million during the years ended December 31, 2013, 2012, 2011, 2010 and 2009, respectively, of depreciation, depletion and amortization attributable to Rendezvous Gas Services, L.L.C and QEP Midstream.

(3) See Note 10 - Commitments and Contingencies to the consolidated financial statements in Item 8 of Part II of this Annual Report.

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 2012 Annual Report on Form 10-K filing, and analyzes the changes in the results of operations between the years ended December 31, 2013 and 2012, and between the years ended December 31, 2012 and 2011.

OVERVIEW

QEP Resources, Inc. (QEP or the Company) is a holding company with three major lines of business: oil and gas exploration and production (QEP Energy); midstream field services (QEP Field Services, including QEP Midstream); and energy marketing (QEP Marketing).

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, Pinedale Anticline, Uinta Basin, Woodford "Cana" shale and Haynesville Shale. These resource plays are characterized by unconventional oil or natural 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 consistent growth in organic production and reserves. QEP believes that it has one of the lowest cash operating structures among its exploration and production company peers. However, in certain of its resource plays, QEP, along with its peers, has experienced increased drilling and completion costs which could impact near term drilling plans.

While historically a natural gas producer, the Company has increased its focus on growing the relative proportion of oil and NGL production in its exploration and production business. During 2013, QEP Energy increased its oil and NGL production by 29% compared to 2012. As part of the Company's liquids growth strategy, 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 2012 Acquisition). Additionally, during the first quarter of 2014, QEP Energy acquired oil and gas properties in the Permian Basin for an aggregate purchase price of approximately $950.0 million, subject to purchase price adjustments.

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 might create significant long-term value. QEP believes that its experience, expertise, and substantial presence in its core operating areas, combined with its low-cost operating model and financial strength, enhance its ability to pursue acquisition opportunities. In addition, the Company will occasionally divest select non-core portfolio assets to redirect capital towards higher-return projects, including $205.8 million of assets sold in 2013. Currently, QEP plans to sell non-core E&P assets located in the Midcontinent during 2014.

QEP owns and operates, directly or through its ownership in QEP Midstream, gathering and natural gas processing and treating facilities in the majority of its core producing areas outside of Oklahoma and Texas. In August 2013, QEP Midstream, a master limited partnership formed by QEP to hold certain midstream gathering assets, completed its IPO. In January 2014, QEP's Board of Directors authorized the Company to develop a plan to separate the business of QEP Field Services, including the Company's interest in QEP Midstream, from QEP.

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 shares. 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.

Financial and Operating Results

For the years ended December 31, 2013 and 2012, QEP Energy reported total equivalent production of 309.0 Bcfe and 319.2 Bcfe, respectively, a decrease of 3% and increase of 16% from the respective 2012 and 2011 comparable periods. Oil and NGL production for the years ended December 31, 2013 and 2012, was 15,021.0 Mbbls and 11,655.9 Mbbls, respectively, a combined increase of 29% and 81% when compared to the prior year periods. The Company's 2012 Acquisition contributed 3,447.9 Mbbls of oil and NGL production during the year ended December 31, 2013.

QEP Field Services' gathering throughput volumes for the years ended December 31, 2013 and 2012, were 13% lower and 2% higher, respectively, than the 2012 and 2011 comparable periods. During the years ended December 31, 2013 and 2012, QEP Field Services reported a 37% decrease and a 3% increase in NGL sales volumes, respectively, and a 1% decrease and 4% increase, respectively, in fee-based processing volumes when compared to the prior year periods.

For the years ended December 31, 2013, 2012 and 2011, QEP Energy's average net realized equivalent prices (including realized commodity derivative impact) were $6.59 per Mcfe, $5.48 per Mcfe and $5.72 per Mcfe, respectively. As a result of low ethane prices relative to natural gas prices, QEP Field Services' processing plants, in regard to its keep-whole processing activities, operated in ethane rejection mode (where the majority of ethane is left in the production stream and sold as natural gas) throughout 2013. When in ethane rejection mode, NGL volumes are lower and average NGL prices are higher as a result of the remaining components of the NGL stream having a higher average unit price than ethane. During the year ended December 31, 2013, QEP Field Services' NGL sales volumes declined by 37%, the impact of which was partially offset by an increase in average net realized NGL sales prices of 11% compared to the prior year. During the years ended December 31, 2013, 2012 and 2011, QEP Field Services' fee-based processing rates increased 7%, 27% and 38%, respectively, while fee-based gathering rates were relatively flat during the same periods.

On August 14, 2013, QEP Midstream completed its IPO of 20,000,000 common units, representing limited partner interests in QEP Midstream, at a price to the public of $21.00 per common unit. QEP Midstream received net proceeds of $390.7 million from the sale of the common units, after deducting underwriting discounts and commissions, structuring fees and offering expenses of approximately $29.3 million. Following the IPO, the underwriters exercised their over-allotment option to purchase an additional 3,000,000 common units, at a price of $21.00 per common unit, providing additional net proceeds of $58.9 million, after deducting $4.1 million of underwriters' discounts and commissions and structuring fees, to QEP Midstream. QEP Midstream used the net proceeds to repay its outstanding debt balance with QEP, which was assumed with the assets contributed to QEP Midstream, pay revolving credit facility origination fees and make a cash distribution to QEP, a portion of which was used to reimburse QEP for certain capital expenditures it incurred with respect to assets contributed to QEP Midstream.

QEP contributed gathering assets which are located in, or within close proximity to, the Green River Basin located in Wyoming and Colorado, the Uinta Basin located in eastern Utah, and the Williston Basin located in North Dakota. QEP utilized the proceeds of the cash distribution it received from QEP Midstream in connection with the IPO to fund ongoing operations, to repay debt under the Company's revolving credit facility and for general corporate purposes. Following the IPO, QEP owns a 57.8% ownership interest in QEP Midstream and consolidates QEP Midstream for financial reporting purposes.

Factors Affecting Results of Operations

Oil, Gas, and NGL Prices
Historically, field-level prices received for QEP's gas, NGL, and oil production have been volatile and unpredictable, and that volatility is expected to continue. In recent years, domestic natural gas supply has grown faster than natural gas demand, 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 natural gas from shale, tight sand formations, and other unconventional reservoirs. Increased natural gas supplies have resulted in downward pressure on natural gas prices, while concern about the global economy and other factors has created volatility in the price of oil. 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 may impact the carrying value of its oil and gas properties.

QEP uses commodity derivatives to reduce the volatility of the prices QEP receives for a portion of its production and to 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, 2013, assuming 2014 annual production of 295 Bcfe, QEP Energy had approximately 57% of its forecasted total production covered with fixed-price swaps, including 53% of its forecasted gas production and 82% of its forecasted oil production. See Item 7A “Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk Management” 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 98% of its forecasted 2014 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 the European debt crisis and its potential impact on global economic growth and the banking and financial sectors, political unrest in the Middle East and Africa, a slowing of growth in Asia, the United States federal budget deficit and debt ceiling crisis, the recent partial shut-down 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 and commodity price volatility. 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, NGL and oil 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
U.S. natural gas directed drilling rig count decreased during 2012, continued to decrease in the first half of 2013 and flattened during the last half of 2013 as producers reduced drilling activity for natural gas in response to lower natural gas prices. A reduction in natural gas production has lagged the downturn in the natural gas rig count, because natural gas producers have a significant inventory of drilled wells waiting on completion, continued efficiency gains have allowed more wells to be drilled and completed per operating rig, and higher per-well natural gas production from horizontal wells now dominates U.S. completions. As a result, U.S. natural gas production has continued to increase despite the decreased rig-count. However, strong natural gas demand from electric power generation and other sources has resulted in a general firming of natural gas prices during the last half of 2012 and 2013. Despite increased natural gas prices during 2013, QEP expects U.S. natural gas prices to remain range-bound over the near term. Relatively low natural gas prices have caused U.S. E&P companies, including QEP, to shift capital investments away from predominantly dry gas areas toward plays that are known to have liquids-rich gas and oil. This shift in focus has caused domestic NGL production to increase dramatically. Increased NGL production, several warmer-than-average winters, 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 crackers are built; however, the prices of heavier components of the NGL barrel have strengthened as a result of recent weather conditions combined with newly commissioned export projects. QEP anticipates global oil prices to remain near current levels, assuming the global economy and socio-political backdrops remain relatively stable. Disruption to the global oil supply system, political and/or economic instability, 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 or Cushing) and global (Brent or U.S. Gulf Coast) markets. Because of the global and regional price volatility and the uncertainty around the commodity price environment, QEP continues to manage its capital spending program and financial flexibility 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 future 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 an impairment of properties. The Company recorded impairments of $93.0 million during the year ended December 31, 2013, primarily due to impairments of goodwill and unproved property 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. During the year ended December 31, 2011, impairments were $218.2 million primarily related to 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, the drilling rig is moved from the location, and the wells are completed, multi-well pad drilling delays the commencement of production, which may cause volatility in QEP’s 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 Condensed Consolidated Financial Statements are prepared in accordance with United States Generally Accepted Accounting

Principles (GAAP). The preparation of the Company’s Condensed 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

Net Income

QEP's net income during the year ended December 31, 2013, was $159.4 million, or $0.89 per diluted share, compared to $128.3 million, or $0.72 per diluted share, in 2012. The increase in net income during 2013 was due to a $38.3 million increase in QEP Energy's net income and a $23.7 million increase in QEP Marketing and Resources' net income partially offset by a $30.9 million decrease in QEP Field Services' 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 Resources' net income is related to intercompany interest income from interest expense charges to QEP's subsidiaries. The decrease in QEP Field Services' net income is due to a 28% decrease in the keep-whole processing margin and a 5% lower gathering margin.

QEP's net income during the year ended December 31, 2012, was $128.3 million, or $0.72 per diluted share, compared to $267.2 million, or $1.50 per diluted share, in 2011. The decrease in net income during 2012 was due to a $104.1 million decrease in QEP Energy's net income, a $25.2 million decrease in QEP Field Services' net income and a $9.6 million decrease in QEP Marketing and Resources' net income. QEP Energy's net income decreased during 2012, due to the accrual of a $115.0 million litigation loss contingency, lower net realized equivalent commodity prices, and an increase in depreciation, depletion and amortization, partially offset by a $68.4 million unrealized gain on commodity derivative contracts, $85.2 million lower proved property impairment charges and production volumes that increased 16%. QEP Field Services' decrease in net income during 2012 was driven by a 35% decrease in the keep-whole processing margin and a 7% lower gathering margin.

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

	Year Ended December 31,			Change	
	2013	2012	2011	**2013 vs 2012**	2012 vs 2011
			(in millions)		
QEP Energy	**$ 38.9**	$ 0.6	$ 104.7	**$ 38.3**	$ (104.1)
QEP Field Services	**98.4**	129.3	154.5	**(30.9)**	(25.2)
QEP Marketing and Resources	**22.1**	(1.6)	8.0	**23.7**	(9.6)
Net income	**$ 159.4**	$ 128.3	$ 267.2	**$ 31.1**	$ (138.9)
Earnings per diluted share	**$ 0.89**	$ 0.72	$ 1.50	**$ 0.17**	$ (0.78)
Average diluted shares	**179.5**	178.7	178.4	**0.8**	0.3

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	
	2013	2012		2011	**2013 vs 2012**	2012 vs 2011
			(in millions)			
QEP Energy	**$ 1,322.7**	$ 1,134.9	115,000,000	$ 1,057.5	**$ 187.8**	$ 77.4
QEP Field Services	**219.9**	274.9		314.4	**(55.0)**	(39.5)
QEP Marketing and Resources	**(5.9)**	(0.8)		8.8	**(5.1)**	(9.6)
Adjusted EBITDA	**$ 1,536.7**	$ 1,409.0		$ 1,380.7	**$ 127.7**	$ 28.3

Adjusted EBITDA increased to $1,536.7 million during the year ended December 31, 2013, compared to $1,409.0 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 at QEP Energy that was partially offset by decreases in processing and gathering margins at QEP Field Services and lower gas and NGL production volumes at QEP Energy.

Adjusted EBITDA increased to $1,409.0 million during the year ended December 31, 2012, compared to $1,380.7 million in 2011. During 2012, QEP Energy's Adjusted EBITDA increased 7%, due to a 16% increase in total production partially offset by 15% lower net realized gas prices and 24% lower net realized NGL prices. QEP Field Services' Adjusted EBITDA decreased 13% due to a decrease in keep-whole processing margins and lower gathering margins.

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, 2013, 2012 and 2011:

	QEP Energy	QEP Field Services	QEP Marketing & Resources	QEP
Year ended December 31, 2013		(in millions)		
Net income attributable to QEP	**38.9**	**98.4**	**22.1**	**$ 159.4**
Unrealized loss (gain) on derivative contracts	**90.7**	**—**	**(2.0)**	**88.7**
Net (gain) loss from asset sales	**(104.1)**	**0.5**	**0.6**	**(103.0)**
Interest and other income	**(3.6)**	**(1.2)**	**(0.4)**	**(5.2)**
Income tax provision	**49.1**	**55.4**	**15.3**	**119.8**
Interest expense (income)[(1)]	**192.6**	**12.7**	**(42.4)**	**162.9**
Depreciation, depletion and amortization[(2)]	**954.2**	**54.1**	**0.9**	**1,009.2**
Impairment	**93.0**	**—**	**—**	**93.0**
Exploration expenses	**11.9**	**—**	**—**	**11.9**
Adjusted EBITDA	**$ 1,322.7**	**$ 219.9**	**$ (5.9)**	**$ 1,536.7**
Year ended December 31, 2012				
Net income (loss) attributable to QEP	0.6	129.3	(1.6)	128.3
Unrealized (gain) loss on derivative contracts	(68.4)	—	5.2	(63.2)
Net gain from asset sales	(1.2)	—	—	(1.2)
Interest and other income	(6.2)	(0.2)	(0.2)	(6.6)
Income tax (benefit) provision	(4.3)	71.8	(1.0)	66.5
Interest expense (income)	116.8	13.6	(7.5)	122.9
Accrued litigation loss contingency[(3)]	115.0	—	—	115.0
Depreciation, depletion and amortization[(2)]	838.4	60.4	3.7	902.5
Loss from early extinguishment of debt	—	—	0.6	0.6
Impairment	133.0	—	—	133.0
Exploration expenses	11.2	—	—	11.2
Adjusted EBITDA	$ 1,134.9	$ 274.9	$ (0.8)	$ 1,409.0
Year ended December 31, 2011				
Net income attributable to QEP	104.7	154.5	8.0	$ 267.2
Unrealized gain on derivative contracts	(117.7)	—	—	(117.7)
Net gain from asset sales	(1.4)	—	—	(1.4)
Interest and other income	(4.0)	(0.1)	—	(4.1)
Income tax provision	57.9	93.4	3.1	154.4
Interest expense (income)	81.9	13.6	(5.5)	90.0
Depreciation, depletion and amortization[(2)]	707.4	53.0	2.5	762.9
Impairment	218.2	—	—	218.2
Exploration expenses	10.5	—	—	10.5
Loss on early extinguishment of debt	—	—	0.7	0.7
Adjusted EBITDA	$ 1,057.5	$ 314.4	$ 8.8	$ 1,380.7

(1) Excludes noncontrolling interest's share of $0.4 million during the year ended December 31, 2013, of interest expense attributable to QEP Midstream.
(2) Excludes noncontrolling interests' share of $6.8 million, $2.8 million and $2.7 million during the years ended December 31, 2013, 2012 and 2011, respectively, of depreciation, depletion and amortization attributable to Rendezvous Gas Services, L.L.C and QEP Midstream.
(3) 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.

QEP Energy

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

	Year Ended December 31,			Change	
	2013	2012	2011	**2013 vs 2012**	2012 vs 2011
	(in millions)				
Revenues					
Gas sales	**$ 779.0**	$ 667.4	$ 1,239.1	**$ 111.6**	$ (571.7)
Oil sales	**916.6**	532.6	324.2	**384.0**	208.4
NGL sales	**192.2**	184.2	129.7	**8.0**	54.5
Purchased gas, oil and NGL sales	**191.6**	222.0	509.8	**(30.4)**	(287.8)
Other	**13.4**	9.2	10.4	**4.2**	(1.2)
Total Revenues	**2,092.8**	1,615.4	2,213.2	**477.4**	(597.8)
Operating expenses					
Purchased gas, oil and NGL expense	**197.1**	224.7	506.4	**(27.6)**	(281.7)
Lease operating expense	**181.3**	175.8	148.2	**5.5**	27.6
Gas, oil and NGL transportation and other handling costs	**242.2**	228.1	186.0	**14.1**	42.1
General and administrative	**139.7**	236.3	98.4	**(96.6)**	137.9
Production and property taxes	**159.8**	97.2	99.1	**62.6**	(1.9)
Depreciation, depletion and amortization	**954.2**	838.4	707.4	**115.8**	131.0
Exploration expenses	**11.9**	11.2	10.5	**0.7**	0.7
Impairment	**93.0**	133.0	218.2	**(40.0)**	(85.2)
Total Operating Expenses	**1,979.2**	1,944.7	1,974.2	**34.5**	(29.5)
Net gain from asset sales	**104.1**	1.2	1.4	**102.9**	(0.2)
Operating Income (Loss)	**217.7**	(328.1)	240.4	**545.8**	(568.5)
Realized gain (loss) on derivative instruments	**149.8**	366.5	(117.7)	**(216.7)**	484.2
Unrealized (loss) gain on derivative instruments	**(90.7)**	68.4	117.7	**(159.1)**	(49.3)
Interest and other income	**3.6**	6.2	4.0	**(2.6)**	2.2
Income from unconsolidated affiliates	**0.2**	0.1	0.1	**0.1**	—
Interest expense	**(192.6)**	(116.8)	(81.9)	**(75.8)**	(34.9)
Income (Loss) before Income Taxes	**88.0**	(3.7)	162.6	**91.7**	(166.3)
Income tax (provision) benefit	**(49.1)**	4.3	(57.9)	**(53.4)**	62.2
Net Income Attributable to QEP	**$ 38.9**	$ 0.6	$ 104.7	**$ 38.3**	$ (104.1)
Production volumes					
Gas (Bcf)	**218.9**	249.3	236.4	**(30.4)**	12.9
Oil (Mbbl)	**10,209.7**	6,306.9	3,741.3	**3,902.8**	2,565.6
NGL (Mbbl)	**4,811.3**	5,349.0	2,715.6	**(537.7)**	2,633.4
Total production (Bcfe)	**309.0**	319.2	275.2	**(10.2)**	44.0
Daily combined production (MMcfe/d)	**846.5**	872.1	753.9	**(25.6)**	118.2

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	
	2013 (1)	2012(1)	2011 (2)	**2013 vs 2012**	2012 vs 2011
Gas (per Mcf)					
Average field-level price	**$ 3.56**	$ 2.68	$ 3.95	**$ 0.88**	$ (1.27)
Commodity derivative impact	**0.69**	1.37	0.79	**(0.68)**	0.58
Net realized price	**$ 4.25**	$ 4.05	$ 4.74	$ 0.20	$ (0.69)
Oil (per bbl)					
Average field-level price	**$ 89.78**	$ 84.45	$ 86.20	**$ 5.33**	$ (1.75)
Commodity derivative impact	**(0.22)**	2.28	0.43	**(2.50)**	1.85
Net realized price	**$ 89.56**	$ 86.73	$ 86.63	**$ 2.83**	$ 0.10
NGL (per bbl)					
Average field-level price	**$ 39.95**	$ 34.43	$ 47.76	**$ 5.52**	$ (13.33)
Commodity derivative impact	**—**	1.90	—	**(1.90)**	1.90
Net realized price	**$ 39.95**	$ 36.33	$ 47.76	**$ 3.62**	$ (11.43)
Average net equivalent price (per Mcfe)					
Average field-level price	**$ 6.11**	$ 4.34	$ 5.04	$ 1.77	$ (0.70)
Commodity derivative impact	**0.48**	1.14	0.68	(0.66)	0.46
Net realized price	**$ 6.59**	$ 5.48	$ 5.72	$ 1.11	$ (0.24)

(1) Beginning January 1, 2012, the impact from commodity derivatives is reported below "Operating income (loss)" in the line item "Realized and unrealized gains on derivative contracts" in the Consolidated Statement of Operations.

(2) For the year ended December 31, 2011, the impact of settled commodity derivatives that qualified for hedge accounting was reported in "Revenues" in the Consolidated Statement of Operations. The impact of the commodity derivatives that did not qualify for hedge accounting was reported below "Operating income (loss)" in the line item "Realized and unrealized gains on derivative contracts" in the Consolidated Statement of Operations.

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, 2013 compared to the years ended December 31, 2012 and 2011:

	Gas	**Oil**	**NGL**	**Total**
	(in millions)			
QEP Energy Production Revenues				
Year ended December 31, 2011 revenues	$ 1,239.1	$ 324.2	$ 129.7	$ 1,693.0
Changes associated with volumes (1)	50.7	221.0	125.8	397.5
Changes associated with prices (2)	(316.9)	(11.0)	(71.3)	(399.2)
Changes associated with discontinuance of hedge accounting (3)	(305.5)	(1.6)	—	(307.1)
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**

(1) The revenue variance attributed to the change in volume is calculated by multiplying the change in volumes from the years ended December 31, 2013 and 2012, as compared to the years ended December 31, 2012 and 2011, by the average field-level price for the years ended December 31, 2012 and 2011.

(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, 2013 and 2012, as compared to the years ended December 31, 2012 and 2011, by the respective volumes for the years ended December 31, 2012 and 2011. Pricing changes are driven by changes in commodity field-level prices, excluding the impact from commodity derivatives.

(3) During the year ended December 31, 2011, realized gains and losses on commodity derivative contract settlements were included in revenues on the Consolidated Statement of Operations. Conversely, during the years ended December 31, 2013 and 2012, the realized gains and losses on commodity derivative contract settlements are recognized below "Operating income (loss)" on the Consolidated Statement of Operations.

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 2012 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 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.

December 31, 2012 compared to December 31, 2011

Gas sales. Gas sales were $667.4 million for the year ended December 31, 2012, a decrease of $571.7 million, or 46%, compared to 2011. This decrease was a result of $1.27 lower average field-level gas prices, partially offset by a 5% increase in gas production to 249.3 Bcfe in 2012 due to the completion of several gas wells during late 2011 and early 2012.

Oil sales. Oil sales were $532.6 million for the year ended December 31, 2012, an increase of $208.4 million, or 64%, compared to 2011. This increase was related to a 69% increase in oil production as a result of QEP's continuing development of oil producing properties including the 2012 Acquisition in the Williston Basin, partially offset by a 2% decrease in average field-level oil prices.

NGL Sales. NGL sales were $184.2 million for the year ended December 31, 2012, an increase of $54.5 million, or 42%, compared to 2011. This increase was a result of a 97% increase in NGL production due to increased production at Pinedale and the Williston Basin related to the 2012 Acquisition partially offset by a 28% decrease in average field-level NGL prices.

QEP Energy Resale Margin

QEP Energy purchases and resells gas, oil and NGL products in order to fulfill firm transportation contract commitments and mitigate potential losses. The difference between the price of the products purchased and sold 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, oil and NGL resale activities:

	Year Ended December 31,			Change	
	2013	2012	2011	**2013 vs 2012**	2012 vs 2011
Resale Margin			(in millions)		
Purchased gas, oil and NGL sales	**$ 191.6**	$ 222.0	$ 509.8	**$ (30.4)**	$ (287.8)
Purchased gas, oil and NGL expense	**197.1**	224.7	506.4	**(27.6)**	(281.7)
Resale margin (loss) gain	**$ (5.5)**	$ (2.7)	$ 3.4	**$ (2.8)**	$ (6.1)

The Company has transportation commitments in excess of its current production as a result of the suspension of its Haynesville drilling program. 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. During the year ended December 31, 2011, QEP Energy recorded a gain on resale margin of $3.4 million.

Operating Expenses

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

	Year Ended December 31,			Change	
	2013	2012	2011	**2013 vs 2012**	2012 vs 2011
			(per Mcfe)		
Depreciation, depletion and amortization	**$ 3.09**	$ 2.63	$ 2.57	**$ 0.46**	$ 0.06
Lease operating expense	**0.59**	0.55	0.54	**0.04**	0.01
Gas, oil and NGL transportation and other handling costs	**0.78**	0.71	0.68	**0.07**	0.03
Production taxes	**0.51**	0.30	0.36	**0.21**	(0.06)
Total Operating Expenses	**$ 4.97**	$ 4.19	$ 4.15	**$ 0.78**	$ 0.04

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 compared to 2012. This increase 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 2012 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 lease operating expense (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**

QEP Energy's 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 2012 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 acquired properties from the 2012 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 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 in the Legacy properties.

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 Part II, Item 8 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.

December 31, 2012 compared to December 31, 2011

Depreciation, depletion and amortization. QEP Energy's DD&A expense increased $131.0 million, or $0.06 per Mcfe, during the year ended December 31, 2012 when compared to 2011. The increase in DD&A expense per Mcfe was the result of increased production from higher-rate DD&A pools and increases in the DD&A rates from increased drilling costs in the Midcontinent and the Williston Basin.

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

	Year Ended December 31,		Change
	2012	2011	2012 vs 2011
Northern Region	$ 0.63	$ 0.58	$ 0.05
Southern Region	0.47	0.50	(0.03)
Average production cost	0.55	0.54	0.01

Lease operating expense increased $27.6 million, or $0.01 per Mcfe, during the year ended December 31, 2012, compared to 2011. The increase during 2012 is primarily due to a $0.05 per Mcfe increase in the Northern Region, which was mostly offset by a $0.03 per Mcfe decrease in the Southern Region. The Northern Region increase was driven by a 41% increase in lease operating expenses, partially offset by a 30% increase in production. The lease operating expense increase in the Northern Region was primarily the result of higher water injection and disposal costs, increased trucking, chemical, labor and pumper costs and increases in workover costs and well maintenance and repair expenses. The Southern Region decrease was a result of a 5% increase in production and a 2% decrease in lease operating expenses. The decrease in lease operating expenses in the Southern Region was driven primarily by decreases in workover costs and well maintenance and repair expenses.

Gas, oil, and NGL transportation and other handling costs. QEP Energy's gas, oil and NGL transportation and other handling costs per Mcfe were 4% higher during the year ended December 31, 2012, than in the year ended December 31, 2011. The per Mcfe increase in 2012 relates to NGL sale agreements at Mont Belvieu, Texas, and the related transportation and processing of NGL, which were effective beginning with the startup of the Blacks Fork II plant in the third quarter of 2011.

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 taxes per Mcfe decreased by $0.06 during 2012 because of lower field-level gas, oil and NGL prices.

Exploration expense. Exploration expenses increased $0.7 million during the year ended December 31, 2012 when compared to 2011 primarily related to increases in exploration-related labor.

Impairment expense. During the year ended December 31, 2012, QEP Energy recorded impairment charges of $133.0 million on certain of its oil and gas properties. The impairment charges related to the reduced value of certain fields resulting from lower gas, oil and NGL prices and impairments of unproven leasehold costs. Proved property impairments were primarily the result of lower gas and NGL prices that impacted the carrying value of proved reserves in several Midcontinent (Oklahoma and Texas) and one Uinta Basin successful efforts pools. Of the $133.0 million impairment charge during 2012, $107.6 million related to the impairment charge on proved properties and $25.4 million related to impairment on unproved properties due to expiration of primary lease terms. Oil and gas properties and leaseholds in the Southern Region accounted for $104.7 million of the $133.0 million impairment charges during 2012, and $28.3 million related to oil and gas properties and leaseholds in the Northern Region.

During the year ended December 31, 2011, QEP recorded impairment charges of $218.2 million, $173.1 million which related to properties in the Northern Region with the remaining $45.1 million related to properties in the Southern Region. Proved property impairments were $195.5 million and unproved property impairments were $22.7 million.

QEP Field Services

During the year ended December 31, 2013, QEP completed the IPO of QEP Midstream. Prior to the IPO on August 14, 2013, QEP Midstream's assets were wholly owned by QEP Field Services. Subsequent to the IPO, QEP Midstream's results are consolidated, with the portion not owned by QEP reflected as noncontrolling interest. Refer to Note 3 - QEP Midstream, in Part II, Item 8 of this Annual Report on Form 10-K for detailed information on the IPO.

The following table provides a summary of QEP Field Services' financial and operating results:

	Year Ended December 31,			Change	
	2013	2012	2011	**2013 vs 2012**	2012 vs 2011
	(in millions)				
Revenues					
NGL sales	**$ 101.9**	$ 137.9	$ 180.0	**$ (36.0)**	$ (42.1)
Processing (fee-based) revenues	**74.7**	69.6	53.7	**5.1**	15.9
Other processing revenues	**13.2**	8.9	2.2	**4.3**	6.7
Gathering revenues	**151.5**	172.9	161.1	**(21.4)**	11.8
Other gathering revenues	**53.3**	36.6	68.5	**16.7**	(31.9)
Purchased gas, oil and NGL sales	**8.8**	13.3	—	**(4.5)**	13.3
Total Revenues	**403.4**	439.2	465.5	**(35.8)**	(26.3)
Operating expenses					
Purchased gas, oil and NGL expense	**8.9**	12.1	—	**(3.2)**	12.1
Processing expense	**16.8**	16.1	12.2	**0.7**	3.9
Processing plant fuel and shrinkage	**31.2**	33.3	49.2	**(2.1)**	(15.9)
Gathering expense	**40.9**	37.4	44.6	**3.5**	(7.2)
Gas, oil and NGL transportation and other handling costs	**13.9**	33.6	9.3	**(19.7)**	24.3
General and administrative	**51.6**	34.4	29.2	**17.2**	5.2
Taxes other than income taxes	**6.6**	6.0	6.1	**0.6**	(0.1)
Depreciation, depletion and amortization	**60.9**	63.2	55.7	**(2.3)**	7.5
Total Operating Expenses	**230.8**	236.1	206.3	**(5.3)**	29.8
Net Loss on Asset Sale	**(0.5)**	—	—	**(0.5)**	—
Operating Income	**172.1**	203.1	259.2	**(31.0)**	(56.1)
Interest and other income	**1.2**	0.2	0.1	**1.0**	0.1
Income from unconsolidated affiliates	**5.6**	6.7	5.4	**(1.1)**	1.3
Realized gains on derivative instruments	**—**	8.4	—	**(8.4)**	8.4
Interest expense	**(13.1)**	(13.6)	(13.6)	**0.5**	—
Income before Income Taxes	**165.8**	204.8	251.1	**(39.0)**	(46.3)
Income tax provision	**(55.4)**	(71.8)	(93.4)	**16.4**	21.6
Net income	**110.4**	133.0	157.7	**(22.6)**	(24.7)
Net income attributable to noncontrolling interest	**(12.0)**	(3.7)	(3.2)	**(8.3)**	(0.5)
Net Income Attributable to QEP	**$ 98.4**	$ 129.3	$ 154.5	**$ (30.9)**	$ (25.2)

Gathering Margin

The following tables are a summary of QEP Field Services' financial and operating results from gathering activities:

	Year Ended December 31,			Change	
	2013	2012	2011	**2013 vs 2012**	2012 vs 2011
Gathering Margin			(in millions)		
Gathering revenues	**$ 151.5**	$ 172.9	$ 161.1	**$ (21.4)**	$ 11.8
Other gathering revenues	**53.3**	36.6	68.5	**16.7**	(31.9)
Gathering expense	**(40.9)**	(37.4) —	(44.6)	**(3.5)**	7.2
Gathering margin	**$ 163.9**	$ 172.1	$ 185.0	**$ (8.2)**	$ (12.9)
Operating Statistics					
Gas gathering volumes (in millions of MMBtu)					
For unaffiliated customers	**219.3**	240.0	261.2	**(20.7)**	(21.2)
For affiliated customers	**221.5**	266.5	234.2	**(45.0)**	32.3
Total gas gathering volumes	**440.8**	506.5	495.4	**(65.7)**	11.1
Average gas gathering revenue (per MMBtu)	**$ 0.34**	$ 0.34	$ 0.33	**$ —**	$ 0.01

During the year ended December 31, 2013, QEP Field Services' gathering margin declined 5% compared to December 31, 2012, primarily due to a 12% decrease in gathering revenues and a 9% increase in gathering expense, partially offset by a 46% increase in other gathering revenue. The decrease in gathering revenues was a result of decreased gathering system throughput volumes of 65.7 million MMBtu, or 13%. This decrease was primarily related to a 43% decline in throughput at QEP Field Services' Northwest Louisiana Hub due to lower QEP Energy production resulting from the suspension of drilling in Haynesville. In addition, gathering revenue decreased 43% at QEP Field Services' Blacks Fork hub due to a higher quantity of volumes being gathered at a lower rate through the system-wide gathering agreement. The increase in gathering expense was primarily the result of increased labor and benefits costs due to additional compensation costs from QEP's annual incentive program. The increase in other gathering revenues was primarily related to increases at the Uinta and North Dakota hubs related to deficiency revenue recognized due to counterparties not fulfilling their minimum volume commitments. The Blacks Fork hub and the Uinta hub accounted for 58% and 17%, respectively, of the total gathering system throughput during 2013.

During the year ended December 31, 2012, QEP Field Services' gathering margin declined 7% compared to December 31, 2011, primarily due to a decrease in other gathering revenue and the related margin from the elimination of a third-party interruptible processing agreement. Partially offsetting the decline in gathering margin was a 2% increase in gathering system throughput volume and a 3% increase in average gas gathering revenue per MMBtu during 2012. Gathering system throughput average volume was 1.4 million MMBtu per day for the year ended December 31, 2012. The 11.1 million MMBtu increase in gathering volumes were mainly related to increased gathering volumes at the Blacks Fork hub in southwest Wyoming and the northwest Louisiana gathering system, which were 2% higher and 12% higher, respectively, during 2012. During 2012, the gathering volume increase at the Blacks Fork hub was driven by a 17.5 million MMBtu increase in affiliated production at Pinedale partially offset by a 9.9 million MMBtu decrease in deliveries from unaffiliated customers. The Blacks Fork hub and the Hall Summit hub accounted for 51% and 23%, respectively, of the total gathering system throughput during 2012.

Processing Margin

The following tables are a summary of QEP Field Services' financial and operating results from processing activities:

	Years ended December 31,			Change	
	2013	2012	2011	**2013 vs 2012**	2012 vs 2011
Processing Margin			(in millions)		
NGL sales [1]	**$ 101.9**	$ 137.9	$ 180.0	**$ (36.0)**	$ (42.1)
Realized gains from commodity derivative contract settlements	**—**	8.4	—	**(8.4)**	8.4
Processing (fee-based) revenues	**74.7**	69.6	53.7	**5.1**	15.9
Other processing revenues	**13.2**	8.9	2.2	**4.3**	6.7
Processing expense	**(16.8)**	(16.1)	(12.2)	**(0.7)**	(3.9)
Processing plant fuel and shrink expense	**(31.2)**	(33.3)	(49.2)	**2.1**	15.9
Gas, oil and NGL transportation and other handling costs	**(13.9)**	(33.6)	(9.3)	**19.7**	(24.3)
Processing margin	**$ 127.9**	$ 141.8	$ 165.2	**$ (13.9)**	$ (23.4)
Keep-whole processing margin [2]	**$ 56.8**	$ 79.4	$ 121.5	**$ (22.6)**	$ (42.1)
Operating Statistics					
Gas processing volumes					
NGL sales (Mbbl)	**2,184.9**	3,470.3	3,376.4	**(1,285.4)**	93.9
Average net realized NGL sales price (per bbl)[3]	**$ 46.65**	$ 42.18	$ 53.33	**$ 4.47**	$ (11.15)
Fee-based processing volumes (in millions of MMBtu)					
For unaffiliated customers	**100.5**	108.2	122.9	**(7.7)**	(14.7)
For affiliated customers	**147.5**	143.1	117.8	**4.4**	25.3
Total fee-based processing volumes	**248.0**	251.3	240.7	**(3.3)**	10.6
Average fee-based processing revenue (per MMBtu)	**$ 0.30**	$ 0.28	$ 0.22	**$ 0.02**	$ 0.06

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

(2) Keep-whole processing margin is calculated as NGL sales less processing plant fuel and shrink, gas, oil and NGL transportation and other handling costs.

(3) Average net realized NGL sales price per bbl is calculated as NGL sales including realized gains from commodity derivative contracts settlements divided by NGL sales volumes.

Although a significant portion of QEP Field Services' gas processing services is performed for a volumetric-based fee, QEP Field Services also provides “keep-whole” processing services for certain customers. Under a keep-whole processing contract, QEP Field Services retains and sells the NGL extracted at its processing plants and keeps the customer “whole” by delivering a Btu-equivalent amount of gas to the customer. Keep-whole processing exposes the Company to the “frac” spread. The frac spread is the difference between the market value of NGL extracted at the processing plant and the market value of an energy-equivalent volume of gas.

During the year ended December 31, 2013, QEP Field Services' keep-whole processing margin decreased 28% compared to 2012, due to a 37% decrease in NGL sales volumes. The decrease in NGL sales volumes was the result of QEP Field Services not recovering ethane on its keep-whole volumes. Partially offsetting this decline was an increase in the average net realized NGL sales price. Including the impact of gains on derivative contract settlements, average NGL realized prices increased 11% during 2013, primarily the result of rejection of ethane, which is normally the lower-value component of the composite NGL barrel. In addition, keep-whole margin was positively impacted in 2013 by a $19.7 million decrease in gas, oil, and NGL transportation and fractionation costs. Transportation costs were lower in 2013 due to the reduction in ethane volumes.

Fee-based processing revenues increased during the year ended December 31, 2013 compared to 2012, due to a 7% increase in the average fee-based processing rate partially offset by a 1% decrease in fee-based processing volumes. Approximately 82% and 77% of QEP Field Services' net operating revenue was derived from fee-based gathering and processing agreements in the years ended December 31, 2013 and 2012, respectively.

During the year ended December 31, 2012, QEP Field Services' keep-whole processing margin decreased 14% compared to 2011, due to a 35% decline in keep-whole processing margins, partially offset by a 40% increase in fee-based processing revenues. During the year ended December 31, 2012, the keep-whole processing margin per NGL barrel was $22.88 compared to $35.99 during the year ended December 31, 2011. Including the impact of gains on derivative contract settlements, NGL prices decreased 21% in 2012, which caused a corresponding decrease in the keep-whole processing margin per NGL bbl. NGL sales volumes increased 3% in 2012, primarily the result of the Blacks Fork II plant, which commenced operations in July 2011, partially offset by the execution, in the second quarter of 2012, of a fee-based processing agreement with QEP Energy in the Uinta Basin that effectively transferred NGL bbls from QEP Field Services to QEP Energy. Transportation and handling costs were $24.3 million higher during the year ended December 31, 2012 compared to 2011, which was the result of additional transportation costs relating to NGL sale agreements that provide for transportation and fractionation of NGL at Mont Belvieu, Texas, and the full year operation of the Blacks Fork II plant, which was put into service in July of 2011.

Fee-based processing revenues increased during the year ended December 31, 2012, due to a 27% increase in the average fee-based processing rate to $0.28 per MMBtu and a 4% increase in fee-based processing volumes to 251.3 million MMBtu. The increased processing volume during the year ended December 31, 2012, was primarily the result of the start-up of the 150 MMcf per day Iron Horse cryogenic processing plant in the Uinta Basin of eastern Utah during the first quarter of 2011 and the start-up of the Blacks Fork II plant in the third quarter of 2011.

QEP Marketing and Resources

The following table provides a summary of QEP Marketing and Resources financial and operating results:

	Year Ended December 31,			Change	
	2013	2012	2011	**2013 vs 2012**	2012 vs 2011
			(in millions)		
Revenues					
Purchased gas, oil and NGL sales	**$ 1,567.4**	$ 1,013.1	$ 1,149.3	**$ 554.3**	$ (136.2)
Other	**5.8**	6.8	7.6	**(1.0)**	(0.8)
Total Revenues	**1,573.2**	1,019.9	1,156.9	**553.3**	(137.0)
Operating expenses					
Purchased gas, oil and NGL expense	**1,570.5**	1,021.1	1,144.5	**549.4**	(123.4)
Gathering, processing and other	**1.7**	1.2	1.3	**0.5**	(0.1)
General and administrative	**4.6**	2.0	2.1	**2.6**	(0.1)
Production and property taxes	**0.1**	0.2	0.2	**(0.1)**	—
Depreciation, depletion and amortization	**0.9**	3.7	2.5	**(2.8)**	1.2
Total Operating Expenses	**1,577.8**	1,028.2	1,150.6	**549.6**	(122.4)
Net loss from asset sales	**(0.6)**	—	—	**(0.6)**	—
Operating (Loss) Income	**(5.2)**	(8.3)	6.3	**3.1**	(14.6)
Realized gain on derivative instruments	**(2.2)**	3.8	—	**(6.0)**	3.8
Unrealized loss on derivative instruments	**2.0**	(5.2)	—	**7.2**	(5.2)
Interest and other income	**206.9**	132.1	98.7	**74.8**	33.4
Loss on extinguishment of debt	**—**	(0.6)	(0.7)	**0.6**	0.1
Interest expense	**(164.1)**	(124.4)	(93.2)	**(39.7)**	(31.2)
(Loss) Income before Income Taxes	**37.4**	(2.6)	11.1	**40.0**	(13.7)
Income tax benefit (provision)	**(15.3)**	1.0	(3.1)	**(16.3)**	4.1
Net (Loss) Income Attributable to QEP	**$ 22.1**	$ (1.6)	$ 8.0	**$ 23.7**	$ (9.6)

Resale Margin

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

	Year Ended December 31,			Change	
	2013	2012	2011	**2013 vs 2012**	2012 vs 2011
Purchased gas, oil and NGL sales	**$ 1,567.4**	$ 1,013.1	$ 1,149.3	**$ 554.3**	$ (136.2)
Purchased gas, oil and NGL expense	**(1,570.5)**	(1,021.1)	(1,144.5)	**(549.4)**	123.4
Realized gain (loss) on derivative instruments	**(2.2)**	3.8	—	**(6.0)**	3.8
Resale margin gain (loss)	**$ (5.3)**	$ (4.2)	$ 4.8	**$ (1.1)**	$ (9.0)

During the years ended December 31, 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 $554.3 million, or 55%, during the year ended December 31, 2013 compared to 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 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.

During the year ended December 31, 2012, purchased gas, oil and NGL sales decreased by $136.2 million compared to the year ended December 31, 2011, due to a $270.9 million decrease in resale gas sales partially offset by a $134.8 million increase in resale oil and NGL sales. Resale gas sales decreased due to a 31% decrease in the resale price and a 9% decrease in resale gas volumes. Resale oil and NGL sales increased due to a 34% increase in resale volumes partially offset by a 1% decrease in resale price.

During the year ended December 31, 2012, purchased gas, oil and NGL expense, which includes transportation expense, decreased $123.4 million compared to the year ended December 31, 2011, due to a $261.3 million decrease in resale gas purchases partially offset by a $134.8 million increase in resale oil and NGL purchases. Resale gas purchases decreased due to a 33% decrease in the resale purchase price and a 4% decrease in resale purchase volumes period to period. Resale oil and NGL sales increased due to a 34% increase in resale purchase volumes partially offset by a 1% decrease in resale purchase price.

OTHER CONSOLIDATED EXPENSES AND INCOME

December 31, 2013 compared to December 31, 2012

General and Administrative. During 2013, general and administrative (G&A) expense decreased $75.5 million, or 28%, compared to 2012. The decrease in G&A in 2013, was primarily due to a $115.0 million litigation loss contingency recognized during 2012 as well as a $5.2 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 $13.4 million increase in labor costs due to the increased number of employees and the Company's annual compensation program, and a $35.9 million increase in professional and outside services including the ongoing implementation of a new Enterprise Resource Planning system, legal costs, QEP Midstream start up costs, feasibility studies, software maintenance costs and other contracted or professional services.

Net gain 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. Both the cash proceeds and gain on sale are subject to post-closing adjustments.

Realized and unrealized gain (loss) 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 $449.3 million, of which $380.0 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 $40.4 million, or 33%, 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 2012 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 the Offering.

Income taxes. Income tax provision increased $53.3 million, or 80%, 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 41.1% during the year ended December 31, 2013, compared to 33.5% for the year ended December 31, 2012. The 2013 combined effective rate was higher due to the impairment of goodwill of $59.5 million that is non-deductible for tax purposes.

December 31, 2012 compared to December 31, 2011

General and Administrative. General and administrative expenses increased by $143.4 million during the year ended December 31, 2012. The increase in G&A expenses for 2012 was primarily the result of the accrual of a $115 million litigation loss contingency. Additional factors contributing to the 2012 increase were $7.0 million in restructuring costs, $2.2 million pension curtailment related to the Company's restructuring efforts (see Note 8 - Restructuring Costs, to the Consolidated Financial Statements of this Annual Report on Form 10-K), $4.7 million in higher compensation costs due to increased number of employees and the annual compensation program, $2.5 million increase in pension and post-retirement medical expenses, $3.6 million increase in stock-based compensation expense, $1.4 million increase from the mark-to-market of the deferred compensation wrap plan, $7.1 million increase in professional and contract services, with the remaining increases related to various immaterial items.

Realized and unrealized gain (loss) on derivative contracts. Effective January 1, 2012, QEP discontinued hedge accounting. As a result, changes during the year ended December 31, 2012, and all changes in the mark-to-market value are recognized in current period earnings. Gains and losses on derivative instruments during 2012 are comprised of both realized and unrealized gains and losses on QEP's commodity derivative contracts and interest rate swaps. During 2012, gains on commodity derivative instruments were $449.3 million, of which $380 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.

During the years ended December 31, 2011, QEP used hedge accounting and changes in the mark-to-market value of the commodity derivative contracts were reflected in accumulated other comprehensive income (AOCI) and ultimately revenues when the commodity derivatives were settled. 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 were being reclassified into the Consolidated Statement of Operations as the transactions settle and affect earnings.

Loss from early extinguishment of debt. During the year ended December 31, 2012, QEP recorded a loss from early extinguishment of debt of $0.6 million from the retirement of a portion of QEP's senior notes. During 2011, QEP recorded a loss from early extinguishment of debt of $0.7 million due to replacing the previous $1.0 billion revolving credit facility with a new $1.5 billion revolving credit facility in August 2011.

Interest expense. Interest expense increased $32.9 million, or 37%, during the year ended December 31, 2012, compared to 2011. The increase in interest expense during 2012 was due to average debt levels that were approximately $856.5 million higher than average debt levels during 2011. The increase in average debt levels is related to QEP issuing 2022 Senior Notes and 2023 Senior Notes and entering into the Term Loan.

Income taxes. Income tax provision decreased $87.9 million, or 57%, during the year ended December 31, 2012, compared to 2011. The decrease was primarily the result of lower income before income taxes and a lower combined effective federal and state income tax rate of 33.5% during the year ended December 31, 2012, compared to 36.3% during 2011. The 2012 combined rate was lower due to state income tax adjustments to prior year provisions based on tax returns filed.

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 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 capital markets and sells properties 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.

In February 2014, the Company acquired oil and gas properties in the Permian Basin for $950.0 million, subject to post closing adjustments. The Permian Basin Acquisition was funded with cash on hand, $300.0 million from the Company's expanded Term Loan and approximately $600.0 million from its revolving credit facility. The Company has commenced a process to sell non-core oil and gas assets in the Midcontinent and initially expects to use any divestiture proceeds to repay indebtedness under its revolving credit facility. The Company expects to have adequate liquidity, prior to the divestitures, to fund its business operations. 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 shares. 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.

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

	December 31,	
	2013	2012
	(in millions, except %)	
Cash and cash equivalents	**$ 11.9**	$ —
Amount available under the QEP credit facility [1]	**1,016.2**	805.9
Total liquidity	**$ 1,028.1**	$ 805.9
Total debt	**$ 2,997.5**	$ 3,206.9
Total common shareholders' equity	**3,376.6**	3,266.0
Ratio of debt to total capital [2]	**47%**	50%

(1) See discussion of revolving credit facility below. Availability under the QEP credit facility is reduced by outstanding letters of credit of $3.8 million as of December 31, 2013, and $4.1 million as of December 31, 2012 and does not include $500.0 million available under QEP Midstream's credit facility.

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

QEP's Credit Facility

QEP's revolving credit facility, which matures in August 2016, provides for loan commitments of $1.5 billion from a syndicate of financial institutions. The credit facility provides for borrowings at short-term interest rates and contains customary covenants and restrictions. The credit facility also contains provisions which would allow for the amount of the facility to be increased to $2.0 billion and the maturity to be extended for two additional one-year periods. QEP's weighted-average interest rate on borrowings from its credit facility was 2.22% and 2.08% during the years ended December 31, 2013 and 2012, respectively. At December 31, 2013, QEP was in compliance with the debt covenants under the credit agreement and had $480.0 million outstanding under its credit facility. At February 20, 2014, QEP had $500.0 million outstanding and $3.8 million of letters of credit issued under its credit facility.

QEP Midstream's Credit Facility

On August 14, 2013, QEP Midstream entered into a $500.0 million senior secured revolving credit facility with a group of financial institutions, which matures on August 14, 2018. The credit facility contains an accordion provision that allows for the amount of the facility to be increased to $750.0 million with the agreement of the lenders. QEP Midstream's credit facility is available for QEP Midstream's working capital, capital expenditures, permitted acquisitions and general corporate purposes, including distributions. In addition, QEP Midstream's credit facility includes a sublimit of up to $50.0 million for letters of credit and a sublimit of up to $25.0 million for swing line loans. Substantially all of QEP Midstream's assets, excluding equity in and assets of certain joint ventures and unrestricted subsidiaries, are pledged as collateral under the credit facility. In addition, the credit agreement contains restrictions and events of default customary for agreements of this nature.

There have been no borrowings under QEP Midstream's credit facility, and at December 31, 2013, QEP Midstream was in compliance with the covenants under the QEP Midstream credit agreement.

QEP is not a borrower or guarantor of QEP Midstream's credit facility. In addition, QEP is not subject to any of the restrictions or covenants contained in QEP Midstream's credit agreement. Outstanding indebtedness under QEP Midstream's credit facility is not included in the definition of indebtedness under QEP's credit agreement.

Term Loan

QEP's $300.0 million term loan facility provides for borrowings at short-term interest rates and contains covenants, restrictions and interest rates that are substantially the same as the Company’s revolving credit facility. The term loan matures in April 2017, and the maturity date may be extended one year with the agreement of the lenders. During the years ended December 31, 2013 and 2012, QEP’s weighted-average interest rate on the term loan was 2.22% and 2.05%, respectively. In conjunction with the term loan, QEP entered into interest rate swap contracts with a combined notional principal amount of $300.0 million which will mature in March 2017. Under the swap contracts, QEP pays 1.07% for the life of the swaps and receives one-month LIBOR. The interest rate at December 31, 2013, under the term loan is one-month LIBOR, plus 2.00% (the Applicable Margin) which, when combined with the fixed interest rate swaps, results in an effective rate of 3.07% for borrowings under the term loan. To the extent that the Applicable Margin under the term loan changes, the effective fixed rate paid for borrowings under the term loan will change. At December 31, 2013 and December 31, 2012, QEP was in compliance with the covenants under the term loan credit agreement.

In February 2014, in conjunction with the Permian Basin Acquisition, the Company increased the term loan to $600.0 million and borrowed the incremental $300.0 million available under the facility. There were no changes to the maturity date, pricing or covenants in the credit agreement.

Senior Notes

The Company's senior unsecured notes outstanding as of December 31, 2013, 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, 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 by operating activities increased $3.4 million during the year ended December 31, 2012, when compared to the year ended December 31, 2011, due to an increase in cash from operating assets and liabilities, partially offset by lower net income and reduced non-cash adjustment to net income. Non-cash adjustments to net income consisted primarily of DD&A; impairment charges; unrealized gains on derivative contracts; and changes in deferred income taxes. Changes in operating assets and liabilities were a source of cash during 2012, primarily due to a decrease in accounts receivable and an increase in accrued expenses from the accrual of $115.0 million for litigation loss contingency.

Net cash provided from operating activities is presented below:

	Year Ended December 31,			Change	
	2013	2012	2011	**2013 vs 2012**	2012 vs 2011
		(in millions)			
Net income	**$ 171.4**	$ 132.0	$ 270.4	**$ 39.4**	$ (138.4)
Non-cash adjustments to net income	**1,196.4**	1,038.0	1,050.9	**158.4**	(12.9)
Changes in operating assets and liabilities	**(176.1)**	126.0	(28.7)	**(302.1)**	154.7
Net cash provided from operating activities	**$ 1,191.7**	$ 1,296.0	$ 1,292.6	**$ (104.3)**	$ 3.4

Cash Flow from Investing Activities

During the year ended December 31, 2013, net cash used in investing activities was $1,441.5 million compared to $2,794.5 million in 2012. This decrease in investing activities was primarily due to the 2012 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.

During the year ended December 31, 2012, cash used in investing activities increased to $2,794.5 million compared to $1,422.9 million during the year ended December 31, 2011. The increase during 2012 was primarily the result of QEP Energy's $1.4 billion 2012 Acquisition.

A comparison of capital expenditures for the year ended December 31, 2013, 2012 and 2011, and a forecast for the calendar year 2014 are presented in the table below:

		Year Ended December 31,			Change	
	2014 Forecast[1]	**2013**	2012	2011	**2013 vs 2012**	2012 vs 2011
			(in millions)			
QEP Energy	$ 1,700.0	**$ 1,467.2**	$ 2,702.4	$ 1,338.8	**$ (1,235.2)**	$ 1,363.6
QEP Field Services	80.0	**86.0**	171.2	101.6	**(85.2)**	69.6
QEP Marketing	0.5	**1.4**	1.0	0.4	**0.4**	0.6
Corporate	24.5	**22.8**	13.6	5.0	**9.2**	8.6
Total accrued capital expenditures	1,805.0	**1,577.4**	2,888.2	1,445.8	**(1,310.8)**	1,442.4
Change in accruals	—	**25.2**	(88.5)	(14.7)	**113.7**	(73.8)
Total cash capital expenditures	$ 1,805.0	**$ 1,602.6**	$ 2,799.7	$ 1,431.1	**$ (1,197.1)**	$ 1,368.6

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

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 QEP Energy's increased capital expenditures in 2012 related to the 2012 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 2012 Acquisition incurred during 2013, compared to $1,406.1 million of property acquisitions in 2012 related to the 2012 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.

QEP Field Services' capital investment decreased $85.2 million, on an accrual basis, during the year ended December 31, 2013 compared to 2012, due to the higher capital expenditures in 2012 for the new 150 MMcf/d cryogenic gas processing plant in the Uinta Basin (Iron Horse II), which was completed during the first quarter of 2013, and the 10,000 Bbl/d expansion of the fractionation facility at the Blacks Fork processing complex. Currently, there are no processing plants under construction at QEP Field Services.

During the year ended December 31, 2012, capital expenditures on a cash basis increased 96% to $2,799.7 million, compared to $1,431.1 million during the year ended December 31, 2011. The increase of $1,368.6 million cash capital expenditures during 2012 was primarily the result of QEP Energy's $1.4 billion 2012 Acquisition. Excluding the 2012 Acquisition, QEP's capital expenditures were $20.1 million lower than in 2011.

QEP Energy's capital investment, on an accrual basis, during the year ended December 31, 2012, increased $1,363.6 million over the year ended December 31, 2011, due to increased capital expenditures in the Williston Basin (primarily due to the 2012 Acquisition), partially offset by lower capital expenditures in Haynesville (approximately 81% lower) due to the reduced drilling program as capital was allocated out of the dry-gas Haynesville play into higher-return oil and liquids-rich gas drilling programs.

QEP Field Services' capital investment increased $69.6 million, on an accrual basis, during the year ended December 31, 2012 compared to 2011, due to projects directed to grow the midstream business. These projects included the construction of a 150 MMcf/d fee-based cryogenic gas processing plant in the Uinta Basin (Iron Horse II) and the 10,000 Bbl/d expansion to the NGL fractionation facilities located at the Blacks Fork processing complex.

At December 31, 2013, forecasted capital investment for 2014 is expected to be approximately $1,805.0 million, comprised of $1,700.0 million allocated to QEP Energy, $80.0 million to QEP Field Services, and $25.0 million between QEP Marketing and Resources. 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 continued low gas prices, QEP plans minimal capital expenditures for the Haynesville Shale and other dry-gas development areas and to increase capital expenditures during 2014 for higher return projects, including oil-directed horizontal drilling in the Williston Basin and the Permian Basin, which was acquired in the first quarter of 2014. QEP Energy has allocated approximately 98% of its forecasted 2014 drilling and completion capital expenditure budget to oil and liquids-rich gas plays. QEP plans to invest a total of approximately $80.0 million in capital expenditures during 2014 to maintain and grow its midstream business, including an expansion of the Vermillion processing plant as well as additional gathering facilities in the Uinta Basin. The remaining QEP Field Services' capital expenditures will be used on compressor projects, new well connections and gathering line expansion. QEP plans to invest approximately $25.0 million in capital expenditures related to corporate activities, primarily the implementation of a new ERP system and building improvements. The aggregate levels of capital expenditures for 2014 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, 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 the IPO 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).

During the year ended December 31, 2012, net cash proceeds from financing activities was $1,498.5 million compared to $130.3 million during the year ended December 31, 2011. During 2012, QEP completed offerings of $650.0 million and $500.0 million of senior notes and entered into a $300.0 million Term Loan. QEP had borrowings under its credit facility of $1,234.5 million and repayments under its credit facility of $1,151.0 million. In addition, QEP retired $6.7 million of its outstanding senior notes. During the years ended December 31, 2012 and 2011 QEP paid dividends of $14.2 million and $14.1 million, respectively. In 2012 and 2011 QEP paid long-term debt issuance costs of $17.8 million and $10.6 million, respectively. At December 31, 2012, long-term debt consisted of $690.0 million outstanding under its credit facility, $300.0 million under the Term Loan and $2,221.8 million in senior notes (excluding $4.9 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, 2013, 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.

Settlement Agreement

On February 13, 2013, QEP executed the Stipulation and Agreement of Settlement related to the litigation with the Chieftain Royalty Company, which provided for a cash settlement payment from QEP in the amount of $115.0 million in exchange for a full release of all claims regarding the calculation, reporting and payment of royalties from the sale of gas and its constituents for all periods prior to February 28, 2013. On May 31, 2013, the Court issued its order approving the settlement, which is now final. At December 31, 2012, QEP recorded an accrual of $115.0 million which was paid and settled in February 2013. See Note 10 - Commitments and Contingencies to the consolidated financial statements in Item 8 of Part II of this Annual Report on Form 10-K for disclosures regarding the settlement agreement.

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, 2013:

	Payments Due by Year [3]						
	Total	2014	2015	2016	2017	2018	After 2018
	(in millions)						
Long-term debt	$ 3,001.8	$ —	$ —	$ 656.8	$ 300.0	$ 134.0	$ 1,911.0
Interest on fixed-rate, long-term debt [1]	989.7	133.0	133.0	129.5	122.3	117.7	354.2
Drilling contracts	54.5	52.4	2.1	—	—	—	—
Firm transportation and storage	332.4	44.6	44.4	42.7	42.0	40.1	118.6
NGL transportation	344.0	43.0	43.0	43.0	43.0	43.0	129.0
Fractionation	113.9	14.2	14.2	14.2	14.2	14.2	42.9
Asset Retirement Obligations [2]	193.6	1.8	3.5	2.8	4.4	2.8	178.3
Operating leases	56.1	7.2	6.5	6.6	6.8	5.3	23.7
Total	$ 5,086.0	$ 296.2	$ 246.7	$ 895.6	$ 532.7	$ 357.1	$ 2,757.7

[1] Excludes variable rate debt interest payments related to the Company's credit facility and Term Loan.
[2] These future obligations are discounted estimates of future expenditures based on expected settlement dates. See Item 8 of Part II of this Annual Report on Form 10-K, Note 5 - Asset Retirement Obligations, for additional information.
[3] This table excludes the Company's benefit plan liabilities as future payment dates are unknown. See Item 8 of Part II of this Annual Report on Form 10-K, Note 12 - Employee Benefits, 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 to the consolidated financial statements included 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 U.S. Generally Accepted Accounting Principles. 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.

QEP Energy engages an independent reservoir engineering consultant 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 17 - Supplemental Oil and Gas Information (Unaudited), of Item 8 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, the delay rental 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 or the unit-of-production method for certain processing plants. 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, other-than-temporary declines in gas, NGL and oil prices and changes in the utilization of midstream gathering and processing assets. 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. Management's assessment of the results of exploration activities and availability of funds for future activities also impact the amounts and timing of impairment provisions. During the years ended December 31, 2013, 2012 and 2011, QEP recorded impairment charges of $1.2 million, $107.6 million and $195.5 million, respectively, on some of its higher cost, proved properties in both of its Northern and Southern regions. The impairment charge related to the reduced value of these areas resulting from lower spot prices and lower forward curve 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, 2013, 2012 and 2011, QEP recorded impairment charges of $32.3 million, $25.4 million and $22.7 million respectively, on its unproved properties.

Goodwill is evaluated on a reporting unit basis for potential impairment. Goodwill is tested for impairment under a two-step quantitative test on an annual basis or when a triggering event occurs. 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 is less than its carrying value, an indication of goodwill impairment exists for the reporting unit and the enterprise must perform step two of the impairment test (measurement). Under step two, an impairment loss is 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 is determined by allocating the fair value of the reporting unit in a manner similar to a purchase price allocation in acquisition accounting. During December 31, 2013, QEP recorded a $59.5 million of impairment of goodwill related to assets in the Uinta Basin.

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 estimate timing of abandonment. QEP's ARO liability at December 31, 2013, 2012 and 2011, was $193.6 million, $193.1 million and $163.9 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 gas, oil and NGL 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 either in net income or Accumulated Other Comprehensive Income (AOCI) depending on the structure of the derivative. Prior to 2012, the Company structured the majority of its energy derivative instruments as cash flow hedges as defined in ASC 815, *Derivatives and Hedging*. Changes in the fair value of cash flow hedges were recorded on the balance sheet and in AOCI until the underlying gas or oil was produced. When a derivative was terminated before its contract expired, the associated gain or loss was recognized in income over the life of the previously hedged production. Changes in the fair value of derivative contracts that did not qualify for hedge accounting were included as part of operating income in the Consolidated Statements of Operations.

Effective January 1, 2012, the Company elected to de-designate all of its gas, oil and NGL derivative contracts that had previously been designated as cash flow hedges at December 31, 2011, and elected to discontinue hedge accounting prospectively. Accordingly, changes in the fair value of commodity derivative contracts are reported in earnings as unrealized gains (losses). See Part II, Item 8, Note 1 - Summary of Significant Accounting Policies, 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. A 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 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 prices. QEP Field Services provides natural gas gathering and transportation services, primarily under fee-based contracts, as well as processing services, under keep-whole and fee-based contracts. In addition, under certain of the gathering agreements, QEP Field Services retains and sells condensate that falls out during the gathering process.

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. Because legal proceedings are inherently unpredictable and unfavorable resolutions could 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, and/or the ongoing discovery and development of information important to the matters. 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 Part II, Item 8, Note 10 - Commitments and Contingencies, 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 Part II, Item 8, Note 10 - Commitments and Contingencies, 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, the rate of future increases in compensation levels of participating employees and the future level of health care costs.

Equity-Based Compensation
QEP uses the Black-Scholes-Merton mathematical model to estimate the fair value of stock options for accounting purposes. The use of this model requires significant judgment with respect to the risk-free interest rate, expected price volatility, expected dividend yield, and expected life.

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 2012 Acquisition in the Williston Basin. In connection with a purchase 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 oil, NGL and gas 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, the discounted future net cash flows of probable and possible reserves are reduced by additional risk-weighting factors.

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 Part II, Item 8, Note 2 - Acquisitions and Divestitures, of this Annual Report on Form 10-K for additional information regarding the 2012 Acquisition.

Recent Accounting Developments

See Recent Accounting Developments in Note 1 - Summary of Significant Accounting Policies to the consolidated financial statements 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 and term loan agreement have 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 fixed-price swaps. 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, 2013, QEP held commodity price derivative contracts totaling 93.4 million MMBtu of gas and 12.8 million barrels of oil. At December 31, 2012, the QEP derivative contracts covered 139.4 million MMBtu of gas and 6.9 million barrels of oil.

The following table presents open 2014 derivative positions, which includes what was in effect as of December 31, 2013 (see Note 7 - Derivative Contracts, under Part II, Item 8 of this Annual Report on Form 10-K for table as of December 31, 2013) and what is known to be in effect as of February 20, 2014:

QEP Energy Commodity Derivative Positions

Year	Type of Contract	Index	Total Volumes	Swaps Average price per unit
			(in millions)	
Gas sales			**(MMBtu)**	
2014	Swap	IFNPCR	61.2	$ 4.02
2014	Swap	NYMEX	24.5	$ 4.22
2015	Swap	NYMEX	25.5	$ 4.14
Oil sales			**(Bbls)**	
2014	Swap	NYMEX WTI	10.5	$ 90.92
2015	Swap	NYMEX WTI	2.9	$ 87.09

QEP Energy Oil Basis Swaps

Year	Index	Index Less Differential	Bbls per Day	Weighted Average Differential
Oil basis swaps				
2014	NYMEX WTI	ICE Brent	2,000.0	$ 13.78
February 2014 - January 2015	NYMEX WTI	LLS	1,000.0	$ 4.00
March 2014 - January 2015	NYMEX WTI	LLS	1,000.0	$ 4.05

QEP Marketing Commodity Derivative Positions

Year	Type of Contract	Index	Total Volumes	Average Swaps price per MMBtu
			(in millions)	
Gas sales			**(MMBtu)**	
2014	Swap	IFNPCR	3.3	$ 3.75
Gas purchases			**(MMBtu)**	
2014	Swap	IFNPCR	1.0	$ 3.86

Changes in the fair value of derivative contracts from December 31, 2012 to December 31, 2013, are presented below:

	Commodity derivative contracts
	(in millions)
Net fair value of gas, oil and NGL derivative contracts outstanding at December 31, 2012	$ 192.8
Contracts settled	(150.3)
Change in oil and gas prices on futures markets	(47.4)
Contracts added	(18.6)
Net fair value of gas, oil and NGL derivative contracts outstanding at December 31, 2013	**$ (23.5)**

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

		December 31, 2013
		(in millions)
Net fair value - asset (liability)	$	(23.5)
Fair value if market prices of gas, oil and NGL and basis differentials decline by 10%		134.6
Fair value if market prices of gas, oil and NGL and basis differentials increase by 10%		(181.7)

Utilizing the actual derivative contractual volumes, a 10% increase in underlying commodity prices would reduce the fair value of these instruments by $158.2 million, while a 10% decrease in underlying commodity prices would increase the fair value of these instruments by $158.1 million as of December 31, 2013. 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, under Part II, Item 8 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, 2013, the Company had $480.0 million outstanding under its credit facility. If interest rates were to increase or decrease 10% during the year ended December 31, 2013, at our average level of borrowing for those same periods, the Company's interest expense would increase or decrease by $1.5 million for the year ended December 31, 2013, or less than 1% of total interest expense.

The Company’s term loan has a floating interest rate which also exposes QEP to interest rate risk. At December 31, 2013, the Company had $300.0 million outstanding under the term loan. During the second quarter of 2012, QEP entered into interest rate swap contracts, with an aggregate notional amount of $300.0 million, to minimize the interest rate volatility risk associated with its $300.0 million term loan. QEP pays a fixed interest rate and receives a floating interest rate indexed to the one-month LIBOR. At December 31, 2013, the fair value of the interest rate swaps was a derivative liability balance of $2.0 million. A 50 basis point decrease would cause the fair value of the interest rate swaps to decrease by $4.3 million while a 50 basis point increase would cause the fair value of the interest rate swaps to increase by $4.7 million.

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, under Part II, Item 8 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 related consolidated statements of operations, comprehensive income, equity, and cash flows present fairly, in all material respects, the financial position of QEP Resources, Inc. at December 31, 2013 and December 31, 2012, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule for the years ended December 31, 2013 and December 31, 2012 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, 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* 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 which were integrated audits in 2013 and 2012. 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.

As discussed in Note 1 to the consolidated financial statements, the Company discontinued hedge accounting effective January 1, 2012.

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.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 25, 2014

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of
QEP Resources, Inc.

We have audited the consolidated statements of operations, comprehensive income (loss), equity, and cash flows for the one year period ended December 31, 2011. Our audits also included the financial statement schedule listed in the Index at Item 8 for the one year period ended December 31, 2011. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated results of QEP Resources, Inc.'s operations and its cash flows for the one year period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ Ernst & Young LLP
Denver, Colorado
February 24, 2012

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2013	2012	2011
REVENUES	(in millions, except per share amounts)		
Gas sales	**$ 779.0**	$ 667.4	$ 1,239.1
Oil sales	**916.6**	532.6	324.2
NGL sales	**294.1**	322.1	309.8
Gathering, processing and other	**189.0**	181.6	200.8
Purchased gas, oil and NGL sales	**757.1**	646.1	1,085.3
Total Revenues	**2,935.8**	2,349.8	3,159.2
OPERATING EXPENSES			
Purchased gas, oil and NGL expense	**765.9**	655.6	1,077.1
Lease operating expense	**177.8**	172.3	145.2
Gas, oil and NGL transport & other handling costs	**141.4**	148.9	102.2
Gathering, processing and other	**90.6**	88.0	107.3
General and administrative	**191.1**	266.6	123.2
Production and property taxes	**166.5**	103.4	105.4
Depreciation, depletion and amortization	**1,016.0**	905.3	765.6
Exploration expenses	**11.9**	11.2	10.5
Impairment	**93.0**	133.0	218.2
Total Operating Expenses	**2,654.2**	2,484.3	2,654.7
Net gain from asset sales	**103.0**	1.2	1.4
OPERATING INCOME (LOSS)	**384.6**	(133.3)	505.9
Realized and unrealized gains on derivative contracts (Note 7)	**58.9**	441.9	—
Interest and other income	**5.2**	6.6	4.1
Income from unconsolidated affiliates	**5.8**	6.8	5.5
Loss from early extinguishment of debt	**—**	(0.6)	(0.7)
Interest expense	**(163.3)**	(122.9)	(90.0)
INCOME BEFORE INCOME TAXES	**291.2**	198.5	424.8
Income taxes	**(119.8)**	(66.5)	(154.4)
NET INCOME	**171.4**	132.0	270.4
Net income attributable to noncontrolling interest	**(12.0)**	(3.7)	(3.2)
NET INCOME ATTRIBUTABLE TO QEP	**$ 159.4**	$ 128.3	$ 267.2
Earnings Per Common Share Attributable to QEP			
Basic	**$ 0.89**	$ 0.72	$ 1.51
Diluted	**$ 0.89**	$ 0.72	$ 1.50
Weighted-average common shares outstanding			
Used in basic calculation	**179.2**	177.8	176.5
Used in diluted calculation	**179.5**	178.7	178.4
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,		
	2013	2012	2011
	(in millions)		
Net income	**$ 171.4**	$ 132.0	$ 270.4
Other comprehensive income, (loss), net of tax:			
Reclassification of previously deferred derivative (gains) losses [1]	**(77.6)**	(171.1)	24.8
Pension and other postretirement plans adjustments:			
Current year net actuarial gain (loss) [2]	**13.5**	(10.0)	(14.7)
Amortization of net actuarial loss [3]	**1.5**	1.1	—
Amortization of net prior service cost [4]	**3.3**	3.5	3.5
Net curtailment cost incurred [5]	**—**	1.4	—
Total pension and other postretirement plans adjustments	**18.3**	(4.0)	(11.2)
Other comprehensive (loss) income	**(59.3)**	(175.1)	13.6
Comprehensive income (loss)	**112.1**	(43.1)	284.0
Comprehensive income attributable to noncontrolling interests	**(12.0)**	(3.7)	(3.2)
Comprehensive income (loss) attributable to QEP	**$ 100.1**	$ (46.8)	$ 280.8

(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, and net of income tax expense of $14.7 million during the year ended December 31, 2011.
(2) Presented 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 and $9.2 million during the years ended December 31, 2012 and December 31, 2011, respectively.
(3) Presented net of income tax expense of $0.9 million and $0.9 million during the years ended December 31, 2013 and 2012, respectively.
(4) Presented net of income tax expense of $2.1 million, $2.2 million and $2.1 million during the years ended December 31, 2013, 2012 and 2011, respectively.
(5) Presented net of income tax expense of $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, 2013	December 31, 2012
ASSETS	(in millions)	
Current Assets		
Cash and cash equivalents	$ **11.9**	$ —
Accounts receivable, net	**408.5**	387.5
Fair value of derivative contracts	**0.2**	188.7
Gas, oil and NGL inventories, at lower of average cost or market	**13.4**	13.1
Deferred income taxes - current	**30.6**	—
Prepaid expenses and other	**54.4**	68.0
Total Current Assets	**519.0**	657.3
Property, Plant and Equipment (successful efforts method for oil and gas properties)		
Proved properties	**11,571.4**	10,234.3
Unproved properties, net	**665.1**	937.9
Midstream field services	**1,698.1**	1,634.9
Marketing and other resources	**85.5**	64.6
Material and supplies	**59.0**	61.9
Total Property, Plant and Equipment	**14,079.1**	12,933.6
Less Accumulated Depreciation, Depletion and Amortization		
Exploration and production	**4,930.9**	4,258.1
Midstream field services	**409.7**	357.9
Marketing and Resources	**22.1**	18.1
Total Accumulated Depreciation, Depletion and Amortization	**5,362.7**	4,634.1
Net Property, Plant and Equipment	**8,716.4**	8,299.5
Investment in unconsolidated affiliates	**39.0**	41.2
Goodwill	**—**	59.5
Fair value of derivative contracts	**1.0**	4.1
Restricted cash	**50.0**	—
Other noncurrent assets	**51.4**	46.9
TOTAL ASSETS	$ **9,376.8**	$ 9,108.5
LIABILITIES AND EQUITY		
Current Liabilities		
Checks outstanding in excess of cash balances	$ **90.9**	$ 39.7
Accounts payable and accrued expenses	**434.9**	643.4
Production and property taxes	**51.8**	41.8
Interest payable	**37.2**	36.9
Fair value of derivative contracts	**26.7**	2.6
Deferred income taxes	**—**	5.0
Total Current Liabilities	**641.5**	769.4
Long-term debt	**2,997.5**	3,206.9
Deferred income taxes	**1,560.6**	1,493.5
Asset retirement obligations	**191.8**	191.4
Fair value of derivative contracts	**—**	3.6
Other long-term liabilities	**108.6**	130.0
Commitments and contingencies (Note 10)		
EQUITY		
Common stock - par value $0.01 per share; 500.0 million shares authorized; 179.3 million and 178.5 million shares issued, respectively	**1.8**	1.8
Treasury stock - 0.4 million and 0.1 million shares, respectively	**(14.9)**	(3.7)
Additional paid-in capital	**498.4**	462.1
Retained earnings	**2,917.8**	2,773.0
Accumulated other comprehensive (loss) income	**(26.5)**	32.8
Total Common Shareholders' Equity	**3,376.6**	3,266.0
Noncontrolling interest	**500.2**	47.7
Total Equity	**3,876.8**	3,313.7
TOTAL LIABILITIES AND EQUITY	$ **9,376.8**	$ 9,108.5

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, 2010	175.9	$ 1.8	(0.1)	$ (3.9)	$ 398.1	$ 2,420.0	$ 194.3	$ 52.8	$ 3,063.1
Net income	—	—	—	—	—	267.2	—	3.2	270.4
Dividends paid	—	—	—	—	—	(14.1)	—	—	(14.1)
Equity-based compensation	1.3	—	(0.3)	(9.2)	33.3	—	—	—	24.1
Distribution from Questar and other	—	—	—	—	—	0.4	—	—	0.4
Distribution of noncontrolling interest	—	—	—	—	—	—	—	(5.4)	(5.4)
Change in unrealized fair value of derivatives, net of tax	—	—	—	—	—	—	24.8	—	24.8
Change in pension and postretirement liability, net of tax	—	—	—	—	—	—	(11.2)	—	(11.2)
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	—	—	—	—	—	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	**—**	**—**	**—**	**—**	**—**	**159.4**	**—**	**12.0**	**171.4**
Dividends paid	**—**	**—**	**—**	**—**	**—**	**(14.3)**	**—**	**—**	**(14.3)**
Equity-based compensation	**0.8**	**—**	**(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	**179.3**	**$ 1.8**	**(0.4)**	**$ (14.9)**	**$ 498.4**	**$ 2,917.8**	**$ (26.5)**	**$ 500.2**	**$ 3,876.8**

See notes accompanying the consolidated financial statements.

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2013	2012	2011
OPERATING ACTIVITIES		(in millions)	
Net income	$ **171.4**	$ 132.0	$ 270.4
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**1,016.0**	905.3	765.6
Deferred income taxes	**66.1**	32.1	156.8
Impairment	**93.0**	133.0	218.2
Equity-based compensation	**27.1**	25.6	22.0
Amortization of debt issuance costs and discounts	**6.4**	5.3	4.1
Net gain from asset sales	**(103.0)**	(1.2)	(1.4)
Income from unconsolidated affiliates	**(5.8)**	(6.8)	(5.5)
Distributions from unconsolidated affiliates and other	**7.9**	7.9	8.1
Non-cash loss on early extinguishment of debt	**—**	—	0.7
Unrealized loss (gain) on derivative contracts	**88.7**	(63.2)	(117.7)
Changes in operating assets and liabilities			
Accounts receivable	**3.2**	9.6	(144.6)
Inventories	**2.6**	28.7	(22.0)
Prepaid expenses	**14.0**	(16.8)	1.6
Accounts payable and accrued expenses	**(179.7)**	101.3	127.8
Federal income taxes	**(27.4)**	3.5	17.0
Other	**11.2**	(0.3)	(8.5)
Net Cash Provided by Operating Activities	**1,191.7**	1,296.0	1,292.6
INVESTING ACTIVITIES			
Property acquisitions	**(40.9)**	(1,406.1)	(48.0)
Property, plant and equipment, including dry hole exploratory well expense	**(1,561.7)**	(1,393.6)	(1,383.1)
Proceeds from disposition of assets	**211.1**	5.2	8.2
Acquisition deposit held in escrow	**(50.0)**	—	—
Net Cash Used in Investing Activities	**(1,441.5)**	(2,794.5)	(1,422.9)
FINANCING ACTIVITIES			
Checks outstanding in excess of cash balances	**51.2**	10.3	9.9
Long-term debt issued	**—**	1,450.0	—
Long-term debt issuance costs paid	**(3.2)**	(17.8)	(10.6)
Long-term debt repaid	**—**	(6.7)	(58.5)
Proceeds from credit facility	**3,085.0**	2,739.0	1,950.3
Repayments of credit facility	**(3,295.0)**	(2,655.5)	(1,743.8)
Treasury stock repurchased	**(9.3)**	—	—
Other capital contributions	**7.0**	(2.2)	0.7
Dividends paid	**(14.3)**	(14.2)	(14.1)
Excess tax benefit on equity-based compensation	**—**	2.2	1.6
Distribution from Questar	—	—	0.2
Net proceeds from the issuance of common units	**449.6**	—	—
Distribution to noncontrolling interest	**(9.3)**	(6.6)	(5.4)
Net Cash Provided by Financing Activities	**261.7**	1,498.5	130.3
Change in cash and cash equivalents	**11.9**	—	—
Beginning cash and cash equivalents	**—**	—	—
Ending cash and cash equivalents	$ **11.9**	$ —	$ —

See notes accompanying the consolidated financial statements.

QEP RESOURCES, INC.
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 three major lines of business: oil and gas exploration and production; midstream field services; and energy marketing. These businesses are conducted through the Company's three principal subsidiaries:

- QEP Energy Company (QEP Energy) acquires, explores for, develops and produces gas, oil, and NGL;
- QEP Field Services Company (QEP Field Services), which includes the ownership and operations of QEP Midstream Partners, LP (QEP Midstream), provides midstream field services, including gathering of natural gas, oil and NGL, natural gas processing, compression, and treating services, for affiliates and third parties, and;
- QEP Marketing Company (QEP Marketing) markets affiliate and third-party oil and gas, and owns and operates an underground gas storage reservoir.

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

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, including QEP Midstream (see Note 3 - QEP Midstream). The consolidated financial statements were prepared in accordance with U.S. Generally Accepted Accounting Principles (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 Form 10-K are in millions, except per-share information and where otherwise noted.

Investment in Unconsolidated Affiliates

QEP uses the equity method to account for investment in unconsolidated affiliates where it does not have control, but has significant influence. The investment in unconsolidated affiliates on the Company's Consolidated Balance Sheets equals the Company's proportionate share of equity reported by the unconsolidated affiliates. Investment is assessed for possible impairment when events indicate that the fair value of the investment may be below the Company's carrying value. When such a condition is deemed to be other than temporary, the carrying value of the investment is written down to its fair value, and the amount of the write-down is included in the determination of net income.

The principal unconsolidated affiliates and QEP's ownership percentage as of December 31, 2013 and 2012, were Uintah Basin Field Services, LLC in which QEP owned (38%) and Three Rivers Gathering, LLC in which QEP Midstream currently owns (50%), which was previously owned by QEP prior to QEP Midstream's initial public offering (see Note 3 - QEP Midstream). Both are limited liability companies engaged in gathering and compressing natural gas.

Reclassifications

In 2012 and 2011, QEP presented certain credit facility payments and borrowings net on the Consolidated Statements of Cash Flow. These borrowings and payments were reclassified to be presented gross on the Consolidated Statement of Cash Flow in order to conform with the current period presentation. This reclassification is entirely within "Financing Activities" and has no effect on other categories or total cash on the Consolidated Statements of Cash Flows or net income or earnings per share on the Consolidated Statements of 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 and goodwill, 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.

Revenue Recognition

QEP subsidiaries recognize revenues in the period that services are provided or products are delivered. Revenues associated with the sale of oil and gas are accounted for using the sales method, whereby revenue is recognized as oil and gas 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, 2013 and 2012, were $18.6 million and $13.2 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*.

QEP Field Services provides gathering and transportation services, primarily under fee-based contracts, as well as processing services, under keep-whole and fee-based contracts. Under fee-based arrangements, QEP Field Services receives a fee or fees for one or more of the following services: firm and interruptible gathering, processing or transmission of natural gas, oil, condensate, and water. The revenue QEP Field Services earns from the fee-based arrangements is generally directly related to the volume of gas, oil, or water that flows through QEP Field Services' systems and is not directly dependent on commodity prices. A portion of the fee-based agreements provide for minimum annual payments or fixed demand charges which are recognized as revenue pursuant to the contract terms. In addition, under the majority of gas gathering agreements, QEP Field Services retains and sells condensate that falls out of the natural gas stream during the gathering process. Under keep-whole arrangements, QEP Field Services processes the natural gas for a customer and takes title to the resulting NGL, which are sold to third parties at market prices. Because the extraction of the NGL from the natural gas during processing reduces the Btu content of the natural gas, QEP Field Services must either purchase gas at market prices for return to producers or make cash payment to the producers equal to the energy content of this gas.

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, 2013, QEP's restricted cash balance was $50.0 million, which consists of a deposit paid by QEP that was held in escrow for the acquisition that closed in the first quarter of 2014 (see Note 15 - Subsequent Event for further discussion on the acquisition). The cash payment is shown in investing activities on the Consolidated Statements of Cash Flow.

Supplemental cash flow information is shown in the below table:

	Year Ended December 31,		
	2013	2012	2011
Supplemental Disclosures:	(in millions)		
Cash paid for interest, net of capitalized interest	**$ 156.7**	105.1	$ 90.5
Cash paid (received) for income taxes	**77.9**	30.0	(28.5)
Non-cash investing activities			
Change in capital expenditure accrual balance	**$ (25.2)**	88.5	$ 14.7

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, 2013, 2012 and 2011, was $3.5 million, $1.4 million, and $0.2 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 $5.1 million at December 31, 2013 and $2.8 million at December 31, 2012.

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 with the exception of compressor maintenance costs, which are capitalized and depreciated. Significant accounting policies for our property, plant and equipment are as follows:

Oil and gas properties

QEP Energy uses the successful efforts method to account for oil and gas properties. The costs of acquiring leaseholds, drilling development wells, drilling successful exploratory wells, purchasing related support equipment and facilities are capitalized. Geological and geophysical studies and other exploratory activities are expensed as incurred. Costs of production and general corporate activities are expensed in the period 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 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 based upon rates that will systematically charge the costs of assets against income over the estimated useful lives of those assets using either a straight-line or unit-of-production method. Investment in gas gathering and processing fixed assets is charged to expense using either the straight-line or unit-of-production method depending upon the facility. 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, declines in gas, NGL and oil prices and changes in the utilization of midstream gathering and processing assets. 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, 2013, QEP recorded impairment charges of $93.0 million, of which $1.2 million relates to price-related impairment charges on proved properties and $32.3 million relates 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 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.

During the year ended December 31, 2011, QEP recorded impairment charges of $218.2 million, of which $173.1 million related to properties in the Northern Region with the remaining $45.1 million related to properties in the Southern Region. Proved property impairments were $195.5 million and unproved property impairments were $22.7 million during the year ended December 31, 2011.

Asset Retirement Obligations
Asset retirement obligations (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.

Capitalized Interest
The Company capitalizes interest costs during the construction phase of large capital projects that meet certain criteria. Capitalized interest was $2.0 million, $3.4 million and $3.0 million during the years ended December 31, 2013, 2012 and 2011, respectively.

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 was reduced to zero from $59.5 million in 2012 due to the recognition of impairment during 2013. Goodwill related to the Company's Uinta Basin reporting unit within QEP Energy. Goodwill is tested for impairment under a two-step quantitative test on an annual basis or when a triggering event occurs. Under the first step, the estimated fair value of the reporting unit is compared with its carrying value (including goodwill). QEP determines fair value of its reporting units in which goodwill is allocated using the income approach in which the fair value is estimated based on the value of expected future cash flows. Key assumptions used in the cash flow model consider 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 exceeds its carrying value, step two does not need to be performed. If the estimated fair value of the reporting unit is less than its carrying value, an indication of goodwill impairment exists for the reporting unit and the enterprise must perform step two of the impairment test (measurement). Under step two, an impairment loss is 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 is 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 is the implied fair value of the reporting unit goodwill. Fair value of the reporting unit under the two-step assessment is determined using a discounted cash flow analysis.

During the performance of QEP's annual goodwill impairment test, 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, 2013 and 2012, an unrealized gain of $88.7 million and an unrealized loss 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. As a result of discontinuing hedge accounting, such mark-to-market values at December 31, 2011, were frozen in AOCI as of the de-designation date and were reclassified into earnings as the original hedged transactions occurred and affected earnings. 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

The Northern and Southern Regions of the United States of America constitute the Company's primary market areas. 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 35%, 37%, and 32% of QEP's revenues for the years ended December 31, 2013, 2012 and 2011, respectively. During the year ended December 31, 2013, Freepoint Commodities, LLC made up 12% of the Company's total revenues. During the year ended December 31, 2012, Chevron U.S.A. Inc. and Enterprise Products Operating, L.P. accounted for 13% and 10%, respectively, of the Company's total revenues. During the year ended December 31, 2011, no customer had sales accounting 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. There were no unrecognized tax benefits at the beginning or end of the twelve-month periods ended December 31, 2013, 2012 and 2011. The federal income tax returns for 2012 and 2011 are currently under examination by the Internal Revenue Service. Income tax returns for 2013 have not yet been filed. Most state tax returns for 2010 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. Acquired treasury stock is used for stock grants to employees; refer to Note 11 - Equity-Based Compensation for additional information.

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, the historical forfeiture rate is minimal and the restricted shares 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. A reconciliation of the components of basic and diluted shares used in the EPS calculation follows:

	December 31,		
	2013	2012	2011
	(in millions)		
Weighted-average basic common shares outstanding	**179.2**	177.8	176.5
Potential number of shares issuable under the Long-Term Stock Incentive Plan	**0.3**	0.9	1.9
Average diluted common shares outstanding	**179.5**	178.7	178.4

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. Additionally, QEP Midstream maintains an equity-based compensation plan for officers, directors and employees of the general partner of QEP Midstream and its affiliates. 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), the rate of future compensation increases and the health care cost trend rate. 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 also 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, QEP Field Services, and QEP Marketing and other corporate activities not attributable to a line of business.

Noncontrolling Interests

Noncontrolling interest represent third-party ownership in the net assets of the Company's consolidated subsidiaries and are presented as a component of equity and net income. Changes in QEP's ownership interest in subsidiaries that do not result in deconsolidation are recognized in equity. On August 14, 2013, QEP completed the initial public offering of QEP Midstream. Prior to the IPO QEP's noncontrolling interest related to the outside ownership of Rendezvous Gas Services, L.L.C. Subsequent to the IPO, QEP Midstream's results (which include Rendezvous Gas Services, L.L.C) are consolidated into QEP as it is a majority-owned and controlled subsidiary and the portion not owned by QEP reflected as noncontrolling interest. See Note 3 - QEP Midstream for further information regarding the IPO.

Recent Accounting Developments

In February of 2013, the FASB issued ASU 2013-02, *Other Comprehensive Income (Topic 220: Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income)*, which seeks to improve the reporting of entities by requiring an entity to report the effect of significant reclassifications out of accumulated other comprehensive income on the respective line items in net income if the amount being reclassified is required under GAAP to be reclassified in its entirety to net income. For other amounts that are not required under GAAP to be reclassified in their entirety to net income in the same reporting period, an entity is required to cross-reference other disclosures required under GAAP that provide additional detail about those amounts. The amendments are effective prospectively for reporting periods beginning on or after December 15, 2012. The

Company adopted this standard in the first quarter of 2013 and noted that it did not have a significant impact on the Company's consolidated financial statements.

In December of 2011, the FASB issued ASU 2011-11, *Disclosures about Offsetting Assets and Liabilities,* which enhances disclosure requirements regarding an entity's financial instruments and derivative instruments that are offset or subject to a master netting arrangement. This information about offsetting and related netting arrangements will enable users of financial statements to understand the effect of those arrangements on the entity's financial position, including the effect of rights of setoff. Additionally, the FASB issued ASU 2013-01, *Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities*, which clarifies the implementation of ASU 2011-01. The amendments are required for annual reporting periods beginning after January 1, 2013, and interim periods within those annual periods. The Company adopted this standard effective January 1, 2013. It did not have a significant impact on the Company's consolidated financial statements.

In July of 2012, the FASB issued ASU 2012-02, *Intangibles - Goodwill and Other: Testing Indefinite-Lived Intangible Assets for Impairment*, which revises the way an entity can test indefinite-lived intangible assets for impairment by allowing an entity to first assess qualitative factors to determine whether the existence of events and circumstances indicates that it is more likely than not that the indefinite-lived intangible asset is impaired. If there is no indication of impairment from the qualitative impairment test, the entity is not required to complete a quantitative impairment test of determining and comparing the fair value with the carrying amount of the indefinite-lived asset. Under the guidance in this ASU, an entity also has the option to bypass the qualitative assessment in any period and proceed directly to performing the quantitative impairment test, while retaining the ability to resume performing the qualitative assessment in any subsequent period. The amendments are effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012. The Company adopted this standard January 1, 2013, which allows the Company to more efficiently complete the annual goodwill impairment test but has not had a significant impact on the Company's consolidated financial statements.

Note 2 - Acquisitions and Divestitures

On September 27, 2012, QEP Energy completed an acquisition of oil and gas properties in the Williston Basin for an aggregate purchase price of $1.4 billion (the 2012 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 2012 Acquisition meets the definition of a business combination under ASC 805, *Business Combinations*, as it included proved properties. QEP allocated the cost of the 2012 Acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Revenues of $300.0 million and $63.7 million and net income of $67.0 million and $14.9 million were generated from the acquired properties during the years ended December 31, 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.

QEP Energy recorded the 2012 Acquisition on its Consolidated Balance Sheets. The following table presents a summary of the purchase accounting entries:

	As of December, 2013	
Consideration given:	(in millions)	
Cash consideration	$	**1,392.7**
Amounts recognized for fair value of assets acquired and liabilities assumed:		
Proved properties	$	**713.8**
Unproved properties		**683.4**
Asset retirement obligations		**(0.9)**
Liabilities assumed		**(4.4)**
Other assets acquired		**0.8**
Total fair value	$	**1,392.7**

The following unaudited, pro forma results of operations are provided for the years ended December 31, 2012 and 2011. 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 years ended December 31, 2012 and 2011, on the acquired properties' historical results of operations and on 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 2012 Acquisition or any estimated costs that have been or will be incurred by the Company to integrate the properties.

	Year ended December 31,			
	2012		2011	
	Actual	Pro forma	Actual	Pro forma
	(in millions, except per share data)			
Revenues	$ 2,349.8	$ 2,485.3	$ 3,159.2	$ 3,236.7
Net income attributable to QEP	128.3	143.0	267.2	259.8
Earnings per common share attributable to QEP				
Basic	$ 0.72	$ 0.80	$ 1.51	$ 1.47
Diluted	0.72	0.80	1.50	1.46

Divestitures

In June 2013, QEP Energy sold its interests in several non-core oil and gas properties located in QEP's Northern Region for total cash 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 total cash proceeds of $67.3 million and recorded a pre-tax gain on sale of $9.5 million. Both the cash proceeds and gains on sales are subject to post-closing adjustments. During the year ended December 31, 2013, QEP Energy recorded these gains on its Consolidated Statements of Operations in "Net gain from asset sales".

Note 3 - QEP Midstream

QEP Midstream is a publicly traded master limited partnership that was formed by QEP to own, operate, acquire and develop midstream energy assets. QEP Midstream's assets currently consist of ownership interests in four gathering systems and two FERC regulated pipelines, which provide oil and gas gathering and transportation services. These assets are located in, or within close proximity to, the Green River Basin located in Wyoming and Colorado, the Uinta Basin located in eastern Utah, and the Williston Basin located in North Dakota.

Initial Public Offering

On August 14, 2013, QEP Midstream completed its initial public offering (the IPO) of 20,000,000 common units, representing limited partner interests in QEP Midstream, at a price to the public of $21.00 per common unit. QEP Midstream received net proceeds of $390.7 million from the sale of the common units, after deducting underwriting discounts and commissions, structuring fees and offering expenses of approximately $29.3 million. Following the IPO, the underwriters exercised their over-allotment option to purchase an additional 3,000,000 common units, at a price of $21.00 per common unit, providing additional net proceeds of $58.9 million, after deducting $4.1 million of underwriters' discounts and commissions and structuring fees, to QEP Midstream.

QEP Midstream used the net proceeds to repay its outstanding debt balance with QEP, which was assumed with the assets contributed to QEP Midstream, pay revolving credit facility origination fees and make a cash distribution to QEP, a portion of which was used to reimburse QEP for certain capital expenditures it incurred with respect to assets contributed to QEP Midstream. The following table is a reconciliation of proceeds from the IPO (in millions):

Total proceeds from the IPO	$	**483.0**
IPO costs		**(33.4)**
Net proceeds from the IPO		**449.6**
QEPM revolving credit facility origination fees		**(3.0)**
QEPM repayment of outstanding debt with QEP		**(95.5)**
Net proceeds distributed to QEP from the Offering	$	**351.1**

QEP Midstream Partners GP, LLC (the General Partner), a wholly owned subsidiary of QEP, serves as the general partner of QEP Midstream. QEP owns a 57.8% interest in QEP Midstream and consolidates QEP Midstream for financial reporting purposes with the portion not owned by QEP reflected as a reduction to net income and equity as a noncontrolling interest.

The following agreements were entered into between QEP and QEP Midstream in connection with the IPO.

Contribution, Conveyance and Assumption Agreement
On August 14, 2013, in connection with the closing of the IPO, QEP entered into a Contribution, Conveyance and Assumption Agreement (the Contribution Agreement) with QEP Field Services, the General Partner and QEP Midstream Partners Operating, LLC (the Operating Company). Immediately prior to the closing of the IPO, the following transactions, among others, occurred pursuant to the Contribution Agreement:

- QEP Field Services contributed to the General Partner, as a capital contribution, a limited liability company interest in the Operating Company with a value equal to 2.0% of the equity value of QEP Midstream at the closing of the IPO;
- the General Partner contributed to QEP Midstream, as a capital contribution, the limited liability company interest in the Operating Company in exchange for (a) 1,090,000 general partner units representing the continuation of an aggregate 2.0% general partner interest in QEP Midstream and (b) all the incentive distribution rights of QEP Midstream;
- QEP Field Services contributed to QEP Midstream, as a capital contribution, its remaining limited liability company interests in the Operating Company in exchange for (a) 6,701,750 common units representing a 12.3% limited partner interest in QEP Midstream, (b) 26,705,000 subordinated units representing a 49.0% limited partner interest in QEP Midstream and (c) the right to receive a distribution from QEP Midstream; and
- the public, through the underwriters, contributed $420.0 million in cash (or $390.7 million, net of the underwriters' discounts and commissions, structuring fees and offering expenses of approximately $29.3 million) to QEP Midstream in exchange for the issuance of 20,000,000 common units.

Subsequent to the IPO, the underwriters exercised their over-allotment option to purchase an additional 3,000,000 common units in QEP Midstream, which reduced QEP's limited partner common unit interest in QEP Midstream from 12.3% to 6.8% and QEP's total ownership interest from 63.3% to 57.8%.

Omnibus Agreement
In connection with the IPO, QEP entered into an Omnibus Agreement (the Omnibus Agreement) with QEP Midstream on August 14, 2013, that addresses the following matters:

- QEP Midstream's payment of an annual amount to QEP, initially in the amount of approximately $13.8 million, for the provision of certain general and administrative services by QEP and its affiliates to QEP Midstream, including a fixed annual fee of approximately $1.4 million for providing certain executive management services by certain officers of the General Partner. The remaining portion of this annual amount reflects an estimate of the costs that QEP and its affiliates expect to incur in providing the services;
- QEP Midstream's obligation to reimburse QEP for any out-of-pocket costs and expenses incurred by QEP in providing general and administrative services (which reimbursement is in addition to certain expenses of the General Partner and its affiliates that are reimbursed under QEP Midstream's partnership agreement), as well as any other out-of-pocket expenses incurred by QEP on QEP Midstream's behalf; and
- an indemnity by QEP for certain environmental and other liabilities, and QEP Midstream's obligation to indemnify QEP and its subsidiaries for events and conditions associated with the operation of QEP Midstream's assets that occur after the closing of the IPO.

As long as QEP controls the General Partner, the Omnibus Agreement will remain in full force and effect. If QEP ceases to control the General Partner, either party may terminate the Omnibus Agreement, but the indemnification obligations will remain in full force and effect in accordance with their terms.

Note 4 - Capitalized Exploratory Well Costs

Net changes in capitalized exploratory well costs are presented in the table below and exclude amounts that were capitalized and subsequently expensed in the period. The balances at December 31, 2013, 2012 and 2011, represent the amount of capitalized exploratory well costs that are pending the determination of proved reserves.

	2013	2012	2011
		(in millions)	
Balance at January 1,	**$ 2.1**	$ 5.0	$ 13.6
Additions to capitalized exploratory well costs pending the determination of proved reserves	**2.7**	12.7	—
Reclassifications to proved properties after the determination of proved reserves	**(2.2)**	(15.6)	(8.3)
Capitalized exploratory well costs charged to expense	**—**	—	(0.3)
Balance at December 31,	**$ 2.6**	$ 2.1	$ 5.0

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, production facilities, midstream assets, 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 $193.6 million and $193.1 million ARO liability for both the years ended December 31, 2013 and 2012, $1.8 million was included as a liability in "Accounts payable and accrued expenses" on the Consolidated Balance Sheet.

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

	Asset Retirement Obligations	
	2013	2012
	(in millions)	
ARO liability at January 1,	**$ 193.1**	$ 163.9
Accretion	**8.9**	10.5
Liabilities incurred	**11.0**	8.5
Revisions	**(4.4)**	11.1
Liabilities related to assets sold	**(11.4)**	—
Liabilities settled	**(3.6)**	(0.9)
ARO liability at December 31,	**$ 193.6**	$ 193.1

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, QEP has interest rate swaps that it has determined are Level 2 financial instruments. The fair values of the interest rate swaps are 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 are based on an expectation of future interest rates derived from observable market interest rate curves. QEP incorporates 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 are not observable inputs, they are not significant to the overall valuation and the other inputs used to value the interest rate swaps are observable Level 2 inputs.

The fair value of financial assets and liabilities at December 31, 2013 and 2012, is shown in the tables below:

	Fair Value Measurements December 31, 2013				
	Gross Amounts of Assets and Liabilities				**Net Amounts Presented on the Condensed Consolidated Balance Sheet**
	Level 1	**Level 2**	**Level 3**	**Netting Adjustments[1]**	
	(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 as the contracts contain netting provisions. Refer to Note 7 - Derivative Contracts, for additional information regarding the Company's derivative contracts.

	Fair Value Measurements December 31, 2012				
	Gross Amounts of Assets and Liabilities				
	Level 1	Level 2	Level 3	Netting Adjustments[1]	Net Amounts Presented on the Condensed Consolidated Balance Sheet
	(in millions)				
Financial Assets					
Commodity derivative instruments - short-term	$ —	$ 189.7	$ —	$ (1.0)	$ 188.7
Commodity derivative instruments - long-term	—	4.2	—	(0.1)	4.1
Total financial assets	$ —	$ 193.9	$ —	$ (1.1)	$ 192.8
Financial Liabilities					
Commodity derivative instruments - short-term	$ —	$ 1.0	$ —	$ (1.0)	$ —
Interest rate swaps - short-term	—	2.6	—	—	2.6
Commodity derivative instruments - long-term	—	0.1	—	(0.1)	—
Interest rate swaps - long-term	—	3.6	—	—	3.6
Total financial liabilities	$ —	$ 7.3	$ —	$ (1.1)	$ 6.2

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

Fair values related to the Company's oil costless collars were transferred from Level 3 to Level 2 in the second quarter of 2012, due to the enhancements to the Company's internal valuation process, including the use of observable inputs to assess the fair value. There were no other significant transfers in or out of Levels 1, 2 or 3 for the periods presented herein.

During the year ended December 31, 2013, there were no derivative instruments assets or liabilities classified as Level 3. The change in the fair value of Level 3 assets and liabilities for the year ended December 31, 2012 is shown below.

	Year Ended December 31, 2012
	(in millions)
Balance at January 1,	$ —
Realized gains and losses	0.6
Unrealized gains and losses	3.8
Settlements	(0.6)
Transfers out of Level 3	(3.8)
Balance at December 31,	$ —

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, 2013				December 31, 2012			
	(in millions)							
Financial assets								
Cash and cash equivalents	**$**	**11.9**	**$**	**11.9**	$	—	$	—
Financial liabilities								
Checks outstanding in excess of cash balances	**$**	**90.9**	**$**	**90.9**	$	39.7	$	39.7
Long-term debt	**$**	**2,997.5**	**$**	**3,034.9**	$	3,206.9	$	3,420.7

The carrying amounts of cash and cash equivalents and checks outstanding in excess of cash balances approximate fair value. The carrying amount of checks outstanding in excess of cash balances approximates 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 quarter. 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 asset retirement obligations 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 asset retirement obligations include 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 and its goodwill 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, 2013 and 2012, 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, 2013 and 2012, the Company recorded $1.2 million and $107.6 million, respectively, of impairments related to certain of its proved properties. The proved properties were written down to their estimated fair values of zero and $71.9 million at the time of the impairments during December 31, 2013 and 2012, 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. Due to the unobservable characteristics of the inputs, the fair value of the properties are 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 extracted NGL volumes in its midstream business and 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 to realize a known price 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. QEP also has oil price derivative swaps that use Intercontinental Exchange, Inc. (ICE), Brent oil prices as the reference price. NGL price derivative instruments are typically structured as Mont Belvieu, Texas fixed-price swaps.

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. During the year ended December 31, 2013, the remaining portion of unrealized gains fixed in AOCI of $77.6 million, net of tax, were settled and reclassified to the Consolidated Statements of Operations. 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 on derivative contracts" below operating income.

QEP also uses interest rate swaps to mitigate a portion of its exposure to interest rate volatility risk. During the second quarter of 2012, QEP entered into variable-to-fixed interest rate swap agreements having a combined notional principal amount of $300.0 million to minimize the interest rate volatility risk associated with its $300.0 million term loan. QEP locked in a fixed interest rate of 1.07% in exchange for a variable interest rate indexed to the one-month LIBOR rate. The interest rate swaps settle monthly and will mature in March of 2017.

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, 2013:

				Swaps	
Year	Type of Contract	Index	Total Volumes	Average price per unit	
			(in millions)		
Gas sales			**(MMBtu)**		
2014	Swap	IFNPCR	58.4	$	3.98
2014	Swap	NYMEX	25.6	$	4.19
2015	Swap	NYMEX	3.7	$	4.16
Oil sales			**(Bbls)**		
2014	Swap	NYMEX WTI	12.1	$	93.68
2015	Swap	NYMEX WTI	0.7	$	88.60

The following table sets forth QEP Energy's oil basis swaps as of December 31, 2013:

Year	Index	Index Less Differential	Bbls Per Day	Weighted Average Differential	
Oil basis swaps					
2014	NYMEX WTI	ICE Brent	2,000.0	$	13.78

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, 2013:

Year	Type of Contract	Index	Total Volumes	Average Swap price per MMBtu
			(in millions)	
Gas sales			**(MMBtu)**	
2014	Swap	IFNPCR	4.7	$ 3.77
Gas purchases			**(MMBtu)**	
2014	Swap	IFNPCR	1.0	$ 3.78

QEP's Derivative Contracts

The following table sets forth QEP's notional amounts and interest rates for its interest rate swaps outstanding as of December 31, 2013:

Notional amount	Type of Contract	Maturity	Fixed Rate Paid	Variable Rate Received
(in millions)				
$300.0	Swap	March 2017	1.07%	One month LIBOR

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	**2013**	2012	**2013**	2012
		(in millions)		(in millions)	
Current:					
Commodity	Fair value of derivative contracts	**$ 5.5**	$ 189.7	**$ 29.4**	$ 1.0
Interest rate swaps	Fair value of derivative contracts	**—**	—	**2.6**	2.6
Long-term:					
Commodity	Fair value of derivative contracts	**0.4**	4.2	**—**	0.1
Interest rate swaps	Fair value of derivative contracts	**0.6**	—	**—**	3.6
Total derivative instruments		**$ 6.5**	$ 193.9	**$ 32.0**	$ 7.3

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:

	Year Ended December 31,		
Derivative instruments not designated as cash flow hedges	**2013**	2012	2011
Realized gains (losses) on commodity derivative contracts		(in millions)	
QEP Energy			
Gas derivative contracts	**$ 152.0**	$ 341.9	$ (117.7)
Oil derivative contracts	**(2.2)**	14.4	—
NGL derivative contracts	**—**	10.2	—
QEP Field Services			
NGL derivative contracts	**—**	8.4	—
QEP Marketing			
Gas derivative contracts	**0.5**	5.1	—
Total realized gains (losses) on commodity derivative contracts	**150.3**	380.0	(117.7)
Unrealized gains (losses) on commodity derivative contracts			
QEP Energy			
Gas derivative contracts	**(42.6)**	37.8	117.7
Oil derivative contracts	**(48.1)**	29.0	—
NGL derivative contracts	**—**	1.6	—
QEP Field Services			
NGL derivative contracts	**—**	—	—
QEP Marketing			
Gas derivative contracts	**(2.1)**	0.9	—
Total unrealized (losses) gains on commodity derivative contracts	**(92.8)**	69.3	117.7
Total realized and unrealized gains on commodity derivative contracts	**$ 57.5**	$ 449.3	$ —
Realized gains (losses) on interest rate swaps			
Realized losses on interest rate swaps	**$ (2.7)**	$ (1.3)	$ —
Unrealized gains (losses) on interest rate swaps			
Unrealized gains (losses) on interest rate swaps	**4.1**	(6.1)	—
Total realized and unrealized gains (losses) on interest rate swaps	**$ 1.4**	$ (7.4)	$ —
Total net realized gains (losses) on derivative contracts	**$ 147.6**	$ 378.7	$ (117.7)
Total net unrealized (losses) gains on derivative contracts	**$ (88.7)**	$ 63.2	$ 117.7
Grand Total	**$ 58.9**	$ 441.9	$ —

The following table presents the change in the fair value and settlement of QEP's derivative contracts that were designated as cash flow hedges in 2011:

Derivative instruments classified as cash flow hedges	**Location of gain (loss) recognized in earnings**	Year Ended December 31, **2013**	2012	2011
Commodity derivatives				
Gain on derivative instruments for the effective portion of hedge recognized in AOCI	Accumulated other comprehensive income	**$ —**	$ —	$ 350.8
Gain reclassified from AOCI into income for effective portion of hedge	Gas sales	**—**	—	305.5
Gain reclassified from AOCI into income for effective portion of hedge	Oil sales	**—**	—	1.6
Gain reclassified from AOCI into income for effective portion of hedge	NGL sales	**—**	—	(0.2)
Gain reclassified from AOCI into income for effective portion of hedge	Marketing purchases	**—**	—	4.3
Gain recognized in income for the ineffective portion of hedges	Interest and other income	**—**	—	0.1

Note 8 - Restructuring Costs

During the first quarter of 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. During the second half of 2012, QEP incurred 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 was intended to increase efficiency, team-based collaboration and organizational productivity over the long term. 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 remaining restructuring costs related to the office consolidations were incurred during 2013.

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 December 31, 2014, conditioned on continued employment with QEP Field Services or a successor through the payment date unless the employee is terminated without cause prior to such date.

The following table summarizes, by line of business, each major type of 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 Restructuring Costs			
		Recognized in Income		
	Total Expected to be Incurred	Period from Inception to December 31, 2013	Year ended December 31,	
			2013	2012
QEP Energy	(in millions)			
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 Field Services				
One-time termination benefits	$ —	$ —	**$ —**	$ —
Retention & relocation expense	10.2	0.9	**0.9**	—
Lease termination costs	—	—	**—**	—
Total restructuring costs	$ 10.2	$ 0.9	**$ 0.9**	$ —
QEP Marketing				
One-time termination benefits	$ 0.3	$ 0.3	**$ 0.1**	$ 0.2
Retention & relocation expense	—	—	**—**	—
Lease termination costs	—	—	**—**	—
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	13.9	4.6	**1.3**	3.3
Lease termination costs	0.6	0.6	**—**	0.6
Total restructuring costs	$ 18.1	$ 8.8	**$ 1.8**	$ 7.0

The following is a reconciliation of the restructuring liability, by line of business, which is included within “Accounts payable and accrued expenses” on the Consolidated Balance Sheets:

	QEP Energy	QEP Field Services	QEP Marketing	Total
	(in millions)			
Balance at December 31, 2012	$ 1.0	$ —	$ —	$ 1.0
Costs incurred and charged to expense	**0.8**	**0.9**	**0.1**	**1.8**
Costs paid or otherwise settled	**(1.8)**	**(0.1)**	**(0.1)**	**(2.0)**
Balance at December 31, 2013	**$ —**	**0.8**	**—**	**$ 0.8**

Note 9 - Debt

As of the indicated dates, the principal amount of QEP’s debt, including amounts outstanding under its and QEP Midstream's revolving credit facilities, QEP's term loan and QEP's senior notes consisted of the following:

	December 31,	
	2013	2012
	(in millions)	
QEP's revolving credit facility due 2016	**$ 480.0**	$ 690.0
QEP Midstream's revolving credit facility due 2018	**—**	—
Term loan due 2017	**300.0**	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	**3,001.8**	3,211.8
Less unamortized discount	**(4.3)**	(4.9)
Total long-term debt outstanding	**$ 2,997.5**	$ 3,206.9

Of the total debt outstanding on December 31, 2013, the revolving credit facility due August 25, 2016, QEP's Midstream's revolving credit facility due August 14, 2018, the term loan due April 18, 2017, 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.

Credit Facilities

QEP's Credit Facility
QEP's revolving credit facility, which matures in August 2016, provides for loan commitments of $1.5 billion from a group of financial institutions. The credit facility provides for borrowings at short-term interest rates and contains customary covenants and restrictions. The credit facility also contains an accordion provision that would allow for the amount of the facility to be increased to $2.0 billion and for the maturity to be extended for two additional one-year periods, with the agreement of the lenders.

During the year ended December 31, 2013 and 2012, QEP's weighted-average interest rate on borrowings from its credit facility was 2.22% and 2.08%, respectively. At December 31, 2013 and 2012, QEP was in compliance with the covenants under the credit agreement. At December 31, 2013, there was $480.0 million outstanding and QEP had $3.8 million in letters of credit outstanding under the credit facility. At December 31, 2012, there was $690.0 million outstanding and QEP had $4.1 million in letters of credit outstanding under the credit facility.

QEP Midstream's Credit Facility
On August 14, 2013, QEP Midstream entered into a $500.0 million senior secured revolving credit facility with a group of financial institutions, which matures on August 14, 2018. QEP Midstream's credit facility contains an accordion provision that allows for the amount of the facility to be increased to $750.0 million with the agreement of the lenders. QEP Midstream's credit facility is available for QEP Midstream's working capital, capital expenditures, permitted acquisitions and general corporate purposes, including distributions. Substantially all of QEP Midstream's assets, excluding equity in and assets of certain joint ventures and unrestricted subsidiaries, are pledged as collateral under the credit facility. In addition, the credit facility contains restrictions and events of default customary for agreements of this nature.

There have been no borrowings under QEP Midstream's credit facility, and at December 31, 2013, QEP Midstream was in compliance with the covenants under the QEP Midstream credit facility agreement.

QEP is not a borrower or guarantor of QEP Midstream's credit facility. In addition, QEP is not subject to any of the restrictions or covenants contained in QEP Midstream's credit agreement. Outstanding indebtedness under QEP Midstream's credit facility is not included in the definition of indebtedness under QEP's credit facility.

Term Loan

QEP's $300.0 million term loan facility provides for borrowings at short-term interest rates and contains covenants, restrictions and interest rates that are substantially the same as QEP’s revolving credit facility. The term loan matures in April 2017, and the maturity date may be extended one year with the agreement of the lenders. During the years ended December 31, 2013 and 2012, QEP's weighted-average interest rate on borrowings from the term loan was 2.22% and 2.05%, respectively. At December 31, 2013 and December 31, 2012, QEP was in compliance with the covenants under the term loan credit agreement.

Senior Notes

At December 31, 2013, 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 indenture governing QEP's senior notes contains customary events of default and covenants that may limit QEP's ability to, among other things, place liens on its property or assets.

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 can be reasonably estimated 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 could 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, and/or the ongoing discovery and development of information important to the matter. QEP's litigation loss contingencies are discussed below. QEP is unable to estimate reasonably possible losses in excess of recorded accruals for these contingencies for the reasons set forth above. QEP believes, however, that the resolution of pending proceedings will not have a material effect on QEP's consolidated financial position, results of operations or cash flows.

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 LDEQ prior to construction, modification, or operation. QEP has corrected and disclosed all instances of non-compliance to the LDEQ and is working with the LDEQ 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

Chieftain Royalty Company v. QEP Energy Company, Case No CIV-11-0212-R, U. S. District Court for the Western District of Oklahoma. This statewide class action was filed in January 2011 on behalf of QEP's Oklahoma royalty owners asserting various claims for damages related to royalty valuation on all of QEP's Oklahoma wells operated by QEP or from which QEP marketed gas. These claims include breach of contract, breach of fiduciary duty, fraud, unjust enrichment, tortious breach of contract, conspiracy, and conversion, based generally on asserted improper deduction of post-production costs. The Court certified the class as to the breach of contract, breach of fiduciary duty and unjust enrichment claims. The parties successfully mediated the case in January 2013. On February 13, 2013, the parties executed a Stipulation and Agreement of Settlement (the Chieftain Settlement Agreement) providing for a cash payment from QEP to the class in the amount of $115.0 million. In consideration for the settlement payment, QEP received a full release of all claims regarding the calculation, reporting and payment of royalties from the sale of gas and its constituents for all periods prior to February 28, 2013, and all class members are enjoined from asserting claims related to such royalties. As part of the Chieftain Settlement Agreement, the parties also agreed on the methodology for the calculation and payment of future royalties payable by QEP, or its successors and assigns, under all class leases for the life of such leases. On May 31, 2013, the Court issued its order approving the settlement, which is now final.

Questar Gas Company v. QEP Field Services Company, Civil No. 120902969, Third Judicial District Court, State of Utah. QEP Field Services' former affiliate, Questar Gas Company (QGC), filed this complaint in state court in Utah on May 1, 2012, asserting claims for breach of contract, breach of implied covenant of good faith and fair dealing, and an accounting and declaratory judgment related to a 1993 gathering agreement (the 1993 Agreement) executed when the parties were affiliates. Specific monetary damages are not asserted. Under the 1993 Agreement, certain of QEP Field Services' systems provide gathering services to QGC charging an annual gathering rate which is based on cost of service. QGC is disputing the annual calculation of the gathering rate. The annual gathering rate has been calculated in the same manner under the 1993 Agreement since it was amended in 1998, without any prior objection or challenge by QGC. At the closing of the IPO, the assets and agreement discussed above were assigned to QEP Midstream. QGC netted the disputed amount from its monthly payments of the gathering fees to QEP Field Services and has continued to net such amounts from its monthly payment to QEP Midstream. As of December 31, 2013, QEP Midstream has deferred revenue of $8.5 million related to the QGC disputed amount. QEP Field Services has filed counterclaims seeking damages and a declaratory judgment relating to its gathering services under the 1993 Agreement. QGC may seek to amend its complaint to add QEP Midstream as a defendant in the litigation. QEP Midstream has been indemnified by QEP for costs, expenses and other losses incurred by QEP Midstream in connection with the QGC dispute, subject to certain limitations, as set forth in the Omnibus Agreement (defined above in "Note 3 - QEP Midstream").

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. Specific monetary damages are not asserted.

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 intend to seek review of the Louisiana Supreme Court, which review is discretionary.

Commitments

Subsidiaries of QEP have contracted for firm transportation 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 and fractionation contracts. Annual payments and the corresponding years for transportation contracts, drilling contracts and fractionation contracts are as follows (in millions):

Year		Amount
2014	$	154.2
2015	$	103.7
2016	$	99.9
2017	$	99.2
2018	$	97.3
After 2018	$	290.5

QEP rents office space throughout its scope of operations from third-party lessors. Rental expense from operating leases amounted to $7.8 million, $7.3 million and $5.0 million during the years ended December 31, 2013, 2012 and 2011, 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
2014	$	7.2
2015	$	6.5
2016	$	6.6
2017	$	6.8
2018	$	5.3
After 2018	$	23.7

Note 11 - Equity-Based Compensation

QEP issues stock options and restricted shares under its LTSIP and awards performance-based 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-based share units vest. Deferred equity-based compensation is included in additional paid-in capital in the Consolidated Balance Sheets. There were 12.0 million shares available for future grants under the LTSIP at December 31, 2013. Equity-based compensation expense is recognized in "General and administrative" on the Consolidated Statements of Operations. During the year ended December 31, 2013, QEP recognized $27.1 million in total compensation expense related to equity-based compensation compared to $25.6 million and $22.0 million during the years ended December 31, 2012 and 2011, respectively.

QEP Midstream maintains a unit-based compensation plan for officers, directors and employees of the general partner of QEP Midstream and its affiliates and any consultants, affiliates of the General Partner, or other individuals who perform services for QEP Midstream. The QEP Midstream 2013 Long-Term Incentive Plan (the QEP Midstream LTIP) permits various types of awards, including awards of restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights, profits interest units and other unit-based awards. Awards granted during 2013 under the QEP Midstream LTIP will be settled with QEP Midstream units. During the year ended December 31, 2013, QEP's equity-based compensation expense included $0.5 million in equity-based compensation related to QEP Midstream's LTIP.

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,		
	2013	2012	2011
Weighted-average grant-date fair value of awards granted during the period	**$ 15.16**	$ 14.29	$ 18.80
Risk-free interest rate range	**0.97%-1.84%**	0.63% - 1.04%	n/a
Weighted-average risk-free interest rate	**1.0%**	0.8%	2.1%
Expected price volatility range	**51.5%-58.5%**	55.9% - 56.5%	n/a
Weighted-average expected price volatility	**58.3%**	55.9%	54.7%
Expected dividend yield	**0.27%**	0.26%	0.21%
Expected term in years at the date of grant	**5.5**	5.0	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, 2012	1,697,471	$ 25.23		
Granted	**330,592**	**30.06**		
Exercised	**(224,833)**	**10.77**		
Forfeited	**(9,043)**	**30.41**		
Outstanding at December 31, 2013	**1,794,187**	**$ 27.90**	**3.67**	**$ 6.5**
Options Exercisable at December 31, 2013	**1,288,844**	**$ 26.63**	**2.90**	**$ 6.4**
Unvested Options at December 31, 2013	**505,343**	**$ 31.14**	**5.88**	**$ 0.1**

The total intrinsic value (the difference between the market price at the exercise date and the exercise price) of options exercised was $4.3 million, $9.6 million and $2.7 million during the years ended December 31, 2013, 2012 and 2011, respectively. The Company realized $1.4 million, $4.6 million, and $0.4 million of income tax benefits for the years ended December 31, 2013, 2012 and 2011. respectively, which increased its Additional Paid-in-Capital (APIC) pool by $6.5 million as of December 31, 2013. As of December 31, 2013, $2.9 million of unrecognized compensation cost related to stock options granted under the LTSIP is expected to be recognized over a weighted-average period of 1.95 years. During the year ended December 31, 2012, QEP issued shares for stock option exercises from its treasury stock. During the year end December 31, 2013, QEP received $2.0 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, 2013, 2012 and 2011, was $19.8 million, $16.7 million and $11.7 million, respectively. The Company realized income tax expense of $0.1 million and $0.3 million for the years ended December 31, 2013 and 2012, respectively, and income tax benefit of $1.0 million during 2011. Restricted stock increased the Company's APIC pool by $0.8 million as of December 31, 2013. The weighted average grant-date fair value of restricted stock granted during the years was $30.06 per share, $30.54 per share and $38.50 per share for the years ended December 31, 2013, 2012 and 2011, respectively. As of December 31, 2013, $17.4 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 1.99 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, 2012	1,300,588	$ 31.78
Granted	**862,669**	**30.06**
Vested	**(665,963)**	**31.42**
Forfeited	**(108,341)**	**30.77**
Unvested balance at December 31, 2013	**1,388,953**	**$ 30.96**

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, 2013, 2012 and 2011, were $30.12, $30.75, and $39.07 per unit, respectively. As of December 31, 2013, $6.4 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 1.83 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, 2012	283,484	$ 33.91
Granted	**223,844**	**30.12**
Vested	**—**	**—**
Forfeited	**(26,668)**	**30.69**
Unvested balance at December 31, 2013	**480,660**	**$ 32.33**

Note 12 - Employee Benefits

Defined Benefit Pension Plans and Other Postretirement Benefits
The Company maintains a closed, defined-benefit pension plan providing coverage to 128, or 13%, of QEP's active employees and to 86 participants that are retired, or terminated and vested. 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 128 active, pension eligible employees, 90 are also eligible for the postretirement medical and life insurance plans when they retire. Currently, 29 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, 2013 and 2012, QEP's accumulated benefit obligation exceeded the fair value of its qualified retirement plan assets. At December 31, 2013 and 2012, QEP's nonqualified retirement plan was unfunded.

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. A curtailment is recognized immediately when there is a significant reduction in, or an elimination of, defined benefit accruals for present employees' future services. For additional information regarding the Company's restructuring see Note 8 - Restructuring Costs. During the year ended December 31, 2013, 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, 2013, the Company made payments of $3.4 million of benefits pursuant to its unfunded nonqualified retirement plan. Payments to the unfunded nonqualified plans are used to fund current benefit payments. During 2014, the Company expects to contribute approximately $8.1 million to its funded pension plan, pay approximately $5.5 million of benefits under its unfunded nonqualified pension plan and pay approximately $0.2 million for retiree health care and life insurance benefits. The accumulated postretirement benefit obligation for all defined-benefit pension plans was $101.0 million and $106.9 million at December 31, 2013 and 2012, 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, 2013 and 2012, as well as the funded status of the plans and amounts recognized in the financial statements at December 31, 2013 and 2012:

	Pension benefits		Other postretirement benefits	
	2013	2012	**2013**	2012
	(in millions)			
Change in benefit obligation				
Benefit obligation at January 1,	**$ 129.7**	$ 104.1	**$ 6.7**	$ 5.9
Service cost	**3.3**	4.0	**0.1**	0.1
Interest cost	**4.8**	5.1	**0.3**	0.3
Change in plan assumptions	**—**	8.4	**—**	—
Benefit payments	**(5.5)**	(2.7)	**(0.1)**	—
Actuarial loss (gain)	**(14.3)**	10.8	**(1.1)**	0.4
Benefit obligation at December 31,	**$ 118.0**	$ 129.7	**$ 5.9**	$ 6.7
Change in plan assets				
Fair value of plan assets at January 1,	**$ 55.3**	$ 44.2	**$ —**	$ —
Actual gain on plan assets	**10.4**	6.9	**—**	—
Company contributions to the plan	**11.5**	6.9	**0.1**	—
Benefit payments	**(5.5)**	(2.7)	**(0.1)**	—
Fair value of plan assets at December 31,	**71.7**	55.3	**—**	—
Underfunded status (current and long-term)	**$ (46.3)**	$ (74.4)	**$ (5.9)**	$ (6.7)
Amounts recognized in balance sheets				
Accounts payable and accrued expenses	**$ (5.5)**	$ (3.2)	**$ (0.2)**	$ (0.2)
Other long-term liabilities	**(40.8)**	(71.2)	**(5.7)**	(6.5)
Total amount recognized in balance sheet	**$ (46.3)**	$ (74.4)	**$ (5.9)**	$ (6.7)
Amounts recognized in AOCI				
Net actuarial loss	**$ 9.5**	$ 32.6	**$ 0.2**	$ 1.3
Prior service cost	**30.1**	35.1	**3.0**	3.4
Total amount recognized in AOCI	**$ 39.6**	$ 67.7	**$ 3.2**	$ 4.7

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		
	2013	2012	2011	**2013**	2012	2011
Components of net periodic benefit cost						
Service cost	**$ 3.3**	$ 4.0	$ 2.9	**$ 0.1**	$ 0.1	$ 0.1
Interest cost	**4.8**	5.1	4.5	**0.3**	0.3	0.3
Expected return on plan assets	**(3.9)**	(3.6)	(2.6)		—	—
Curtailment loss	**—**	2.2	—	**—**	—	—
Amortization of prior service costs	**5.0**	5.3	5.3	**0.3**	0.3	0.3
Amortization of actuarial loss	**2.3**	1.9	—	**0.1**	0.1	—
Periodic expense	**$ 11.5**	$ 14.9	$ 10.1	**$ 0.8**	$ 0.8	$ 0.7
Components recognized in accumulated other comprehensive income						
Current period actuarial loss (gain)	**$ (20.8)**	$ 15.9	$ 22.9	**$ (1.0)**	$ 0.4	$ 1.0
Amortization of actuarial loss	**(2.3)**	(1.9)	—	**(0.1)**	(0.1)	—
Current period prior service cost	**—**	—			—	—
Amortization of prior service cost	**(5.0)**	(5.3)	(5.3)	**(0.4)**	(0.4)	(0.3)
Loss on curtailment in current period		(2.2)	—	**—**	—	—
Total amount recognized in accumulated other comprehensive income	**$ (28.1)**	$ 6.5	$ 17.6	**$ (1.5)**	$ (0.1)	$ 0.7

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 2014 is $5.0 million, which represents amortization of prior service cost recognition. The estimated portion to be recognized in net periodic cost for other postretirement benefits from AOCI in 2014 is $0.4 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, 2013 and 2012:

	Pension benefits		Other postretirement benefits	
	2013	2012	**2013**	2012
Discount rate	**4.75%**	3.88%	**5.00%**	4.10%
Rate of increase in compensation	**4.00%**	3.60%	**4.00%**	3.60%

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		
	2013	2012	2011	**2013**	2012	2011
Discount rate	**3.69%**	4.38%	5.80%	**4.10%**	4.70%	5.80%
Expected long-term return on plan assets	**6.75%**	7.25%	7.50%	**n/a**	n/a	n/a
Rate of increase in compensation	**3.60%**	3.60%	3.60%	**3.60%**	4.00%	n/a

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 2014. 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 increase 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 mostly invested in a stock index fund, and a smaller portion was invested in an actively managed product, 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.

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, 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%**

	December 31, 2012				
	Level 1	Level 2	Level 3	Total	Percentage of total
	(in millions except percentages)				
Cash and short-term investments	$ —	$ —	$ 0.2	$ 0.2	$ —
Equity securities:					
Domestic	—	—	22.2	22.2	40%
International	—	—	16.6	16.6	30%
Fixed income	—	—	16.2	16.2	30%
Total investments	—	—	$ 55.2	$ 55.2	100%

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

	Year ended December 31,	
	2013	2012
	(in millions)	
Balance at January 1,	**$ 55.2**	44.2
Employer contributions	**8.1**	5.6
Unrealized gains (losses)	**9.8**	6.3
Realized gains	**0.9**	0.7
Administrative fees	**(0.3)**	(0.2)
Benefits paid	**(2.1)**	(1.4)
Balance at December 31,	**$ 71.6**	$ 55.2

Expected Benefit Payments

As of December 31, 2013, the following future benefit payments are expected to be paid:

	Pension	Postretirement benefits
	(in millions)	
2014	$ 8.1	$ 0.2
2015	5.8	0.2
2016	6.1	0.3
2017	4.7	0.3
2018	5.8	0.3
2019 through 2021	40.0	1.8

Employee Investment Plan

QEP employees may participate in the QEP Employee Investment Plan (EIP), a defined-contribution plan. The EIP allows eligible employees to purchase shares of QEP common stock or other investments through payroll deduction at the current fair market value on the transaction date. For the year ended December 31, 2013, the Company made discretionary matching contributions equal to 100% of employees' contributions up to a maximum of 8% of their qualifying earnings. Employees in the closed QEP Resources, Inc. Retirement Plan (pension) are eligible for a 6% match. For the years ended December 31, 2012 and 2011, the Company made discretionary 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 discretionary matching contribution to employees not in the QEP Resources, Inc. Retirement Plan (pension), and for the years ended December 31, 2012 and 2011, 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 $6.9 million, $6.4 million and $5.8 million during the years ended December 31, 2013, 2012 and 2011, respectively.

Note 13 - Income Taxes

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

	Year Ended December 31,		
	2013	2012	2011
		(in millions)	
Federal income tax expense (benefit)			
Current	**$ 47.9**	$ 33.7	$ (5.3)
Deferred	**69.1**	36.5	153.0
State income tax expense (benefit)			
Current	**5.7**	0.7	2.9
Deferred	**(2.9)**	(4.4)	3.8
Total income tax expense	**$ 119.8**	$ 66.5	$ 154.4

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

	Year Ended December 31,		
	2013	2012	2011
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	**0.6 %**	(1.2)%	1.0 %
Penalties	**0.2 %**	(0.6)%	— %
Return to provision adjustment	**(0.2)%**	0.4 %	1.3 %
Noncontrolling interest	**(1.4)%**	(0.7)%	(0.3)%
Book impairment of goodwill	**7.2 %**	— %	— %
Other	**(0.3)%**	0.6 %	(0.7)%
Effective income tax rate	**41.1 %**	33.5 %	36.3 %

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

	December 31,	
	2013	2012
	(in millions)	
Deferred tax liabilities		
Property, plant and equipment	**$ 1,651.1**	$ 1,606.6
Commodity price and interest rate derivatives	**—**	69.4
Total deferred tax liabilities	**1,651.1**	1,676
Deferred tax assets		
Commodity price and interest rate derivatives	**9.7**	—
Net operating loss and tax credit carryforwards	**54.6**	65.6
Employee benefits and compensation costs	**36.1**	47.7
Accrued litigation loss contingency	**0.8**	42.8
Bonus and vacation accrual	**10.6**	11.8
Other	**9.3**	9.6
Total deferred tax assets	**121.1**	177.5
Net deferred income tax liability	**$ 1,530.0**	$ 1,498.5
Balance sheet classification		
Deferred income tax asset - current	**$ 30.6**	$ —
Deferred income tax liability -current	**—**	$ 5.0
Deferred income tax liability - non-current	**1,560.6**	1,493.5
Net deferred income tax liability	**$ 1,530.0**	$ 1,498.5

The amounts and expiration dates of net operating loss and tax credit carryforwards at December 31, 2013 are as follows:

	Expiration Dates	Amounts
		(in millions)
State net operating loss and tax credit carryforwards	2014-2032	**$ 26.5**
U.S. alternative minimum tax credit	Indefinite	**28.1**
Total		**$ 54.6**

Note 14 - Operations by Line of Business

QEP's lines of business include oil and gas exploration and production (QEP Energy), midstream field services (QEP Field Services), which includes the ownership and operation of QEP Midstream, and marketing and corporate (QEP Marketing & Resources). 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. QEP owns a 57.8% ownership interest in QEP Midstream and it is consolidated under the voting interest model in QEP Field Services' operating results. The outside ownership interest in QEP Midstream is presented separately as a noncontrolling interest.

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

	QEP Energy	QEP Field Services	QEP Marketing & Resources	Eliminations	QEP Consolidated
			(in millions)		
Revenues (1)					
From unaffiliated customers	$ 2,092.8	$ 282.4	$ 560.6	$ —	$ 2,935.8
From affiliated customers	—	121.0	1,012.6	(1,133.6)	—
Total Revenues	2,092.8	403.4	1,573.2	(1,133.6)	2,935.8
Operating expenses					
Purchased gas, oil and NGL expense	197.1	8.9	1,570.5	(1,010.6)	765.9
Lease operating expense	181.3	—	—	(3.5)	177.8
Gas, oil and NGL transportation and other handling costs	242.2	13.9	—	(114.7)	141.4
Gathering, processing and other	—	88.9	1.7	—	90.6
General and administrative	139.7	51.6	4.6	(4.8)	191.1
Production and property taxes	159.8	6.6	0.1	—	166.5
Depreciation, depletion and amortization	954.2	60.9	0.9	—	1,016.0
Impairment and exploration expenses	104.9	—	—	—	104.9
Total operating expenses	1,979.2	230.8	1,577.8	(1,133.6)	2,654.2
Net gain (loss) from asset sales	104.1	(0.5)	(0.6)	—	103.0
Operating income (1)	217.7	172.1	(5.2)	—	384.6
Realized and unrealized gains (losses) on derivative contracts	59.1	—	(0.2)	—	58.9
Interest and other income	3.6	1.2	206.9	(206.5)	5.2
Income from unconsolidated affiliates	0.2	5.6	—	—	5.8
Loss on early extinguishment of debt	—	—	—	—	—
Interest expense	(192.6)	(13.1)	(164.1)	206.5	(163.3)
Income before income taxes	88.0	165.8	37.4	—	291.2
Income tax	(49.1)	(55.4)	(15.3)	—	(119.8)
Net income	38.9	110.4	22.1	—	171.4
Net income attributable to noncontrolling interest	—	(12.0)	—		(12.0)
Net income attributable to QEP (2)	$ 38.9	$ 98.4	$ 22.1	$ —	$ 159.4
Identifiable total assets	$ 7,930.6	$ 1,455.1	$ 250.7	$ (259.6)	$ 9,376.8
Investment in unconsolidated affiliates		39.0	—	—	39.0
Cash capital expenditures	1,488.6	89.8	24.2	—	1,602.6
Accrued capital expenditures	1,467.2	86.0	24.2	—	1,577.4

(1) The impact of QEP's settled derivative contracts, for the year ended December 31, 2013, is reflected below operating income.
(2) Net income attributable to QEP for the year ended December 31, 2013, includes the impact of unrealized gains and losses from changes in the fair value of the commodity derivative contracts.

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

	QEP Energy	QEP Field Services	QEP Marketing & Resources	Eliminations	QEP Consolidated
			(in millions)		
Revenues [1]					
From unaffiliated customers	$ 1,615.4	$ 320.2	$ 414.2	$ —	$ 2,349.8
From affiliated customers	—	119.0	605.7	(724.7)	—
Total Revenues	1,615.4	439.2	1,019.9	(724.7)	2,349.8
Operating expenses					
Purchased gas, oil and NGL expense	224.7	12.1	1,021.1	(602.3)	655.6
Lease operating expense	175.8	—	—	(3.5)	172.3
Gas, oil and NGL transportation and other handling costs	228.1	33.6	—	(112.8)	148.9
Gathering, processing and other	—	86.8	1.2	—	88.0
General and administrative	236.3	34.4	2.0	(6.1)	266.6
Production and property taxes	97.2	6.0	0.2	—	103.4
Depreciation, depletion and amortization	838.4	63.2	3.7	—	905.3
Impairment and exploration expenses	144.2	—	—	—	144.2
Total operating expenses	1,944.7	236.1	1,028.2	(724.7)	2,484.3
Net gain from asset sales	1.2	—	—	—	1.2
Operating (loss) income	(328.1)	203.1	(8.3)	—	(133.3)
Realized and unrealized gains (losses) on derivative contracts	434.9	8.4	(1.4)	—	441.9
Interest and other income	6.2	0.2	132.1	(131.9)	6.6
Income from unconsolidated affiliates	0.1	6.7	—	—	6.8
Loss on extinguishment of debt	—	—	(0.6)	—	(0.6)
Interest expense	(116.8)	(13.6)	(124.4)	131.9	(122.9)
(Loss) income before income taxes	(3.7)	204.8	(2.6)	—	198.5
Income taxes benefit (provision)	4.3	(71.8)	1.0	—	(66.5)
Net income (loss)	0.6	133.0	(1.6)	—	132.0
Net income attributable to noncontrolling interest	—	(3.7)	—	—	(3.7)
Net income (loss) attributable to QEP	$ 0.6	$ 129.3	$ (1.6)	$ —	$ 128.3
Identifiable total assets	$ 7,436.5	$ 1,399.7	$ 272.3	$ —	$ 9,108.5
Investment in unconsolidated affiliates	—	41.2	—	—	41.2
Cash capital expenditures	2,621.1	164.0	14.6	—	2,799.7
Accrued capital expenditures	2,702.4	171.2	14.6	—	2,888.2
Goodwill	59.5	—	—	—	59.5

[1] The impact of QEP's settled derivative contracts, for the year ended December 31, 2012, was reflected below operating (loss) income.
[2] Net (loss) income attributable to QEP for the year ended December 31, 2012, includes the impact of unrealized gains and losses from changes in the fair value of the commodity derivative contracts.

The following table is a summary of operating results for the year ended December 31, 2011, by line of business:

	QEP Energy	QEP Field Services	QEP Marketing & Resources	Eliminations	QEP Consolidated
			(in millions)		
Revenues [(1)]					
From unaffiliated customers	$ 2,213.2	$ 369.3	$ 576.7	$ —	$ 3,159.2
From affiliated customers	—	96.2	580.2	(676.4)	—
Total Revenues	2,213.2	465.5	1,156.9	(676.4)	3,159.2
Operating expenses					
Purchased gas, oil and NGL expense	506.4	—	1,144.5	(573.8)	1,077.1
Lease operating expense	148.2	—	—	(3.0)	145.2
Gas, oil and NGL transportation and other handling costs	186.0	9.3	—	(93.1)	102.2
Gathering, processing and other	—	106.0	1.3	—	107.3
General and administrative	98.4	29.2	2.1	(6.5)	123.2
Production and property taxes	99.1	6.1	0.2	—	105.4
Depreciation, depletion and amortization	707.4	55.7	2.5	—	765.6
Impairment and exploration expenses	228.7	—	—	—	228.7
Total operating expenses	1,974.2	206.3	1,150.6	(676.4)	2,654.7
Net gain from asset sales	1.4	—	—	—	1.4
Operating income [(2)]	240.4	259.2	6.3	—	505.9
Interest and other income	4.0	0.1	98.7	(98.7)	4.1
Income from unconsolidated affiliates	0.1	5.4	—	—	5.5
Loss on extinguishment of debt	—	—	(0.7)	—	(0.7)
Interest expense	(81.9)	(13.6)	(93.2)	98.7	(90.0)
Income before income taxes	162.6	251.1	11.1	—	424.8
Income taxes	(57.9)	(93.4)	(3.1)	—	(154.4)
Net Income	104.7	157.7	8.0	—	270.4
Net income attributable to noncontrolling interest	—	(3.2)	—	—	(3.2)
Net income attributable to QEP [(3)]	$ 104.7	$ 154.5	$ 8.0	$ —	$ 267.2
Identifiable assets	$ 5,815.7	$ 1,312.7	$ 314.3	$ —	$ 7,442.7
Investment in unconsolidated affiliates	—	42.2	—	—	42.2
Cash capital expenditures	1,295.5	130.1	5.5	—	1,431.1
Accrued capital expenditures	1,338.8	101.6	5.5	—	1,445.9
Goodwill	59.5	—	—	—	59.5

(1) Revenues for the year ended December 31, 2011, reflect the impact of QEP's settled derivative contracts. See Note 7 - Derivative Contracts, for detailed information on derivative contract settlements in the year ended December 31, 2011.
(2) Under hedge accounting, realized gains and losses from realized commodity derivative contract settlements were included in revenues and operating income during the year ended December 31, 2011.
(3) Under hedge accounting, unrealized gains and losses from changes in the fair value were deferred in AOCI during the year ended December 31, 2011.

Note 15 - Subsequent Event

In February 2014, QEP Energy acquired oil and gas properties in the Permian Basin of Texas for an aggregate purchase price of $950.0 million, subject to customary 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 260 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 cash on hand, $300.0 million from the Company's expanded Term Loan and approximately $600.0 million from its revolving credit facility. Based on the timing of the Permian Basin Acquisition, QEP has not completed its initial accounting for the Permian Basin Acquisition and thus full disclosures required under GAAP will not be included until the first quarter 2014.

In February 2014, to fund a portion of the purchase price for the Permian Basin Acquisition, the Company increased the term loan from $300.0 million to $600.0 million. There were no changes to the maturity date, pricing or covenants in the term loan credit agreement.

Note 16 - 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)		
2013					
Revenues	**$ 696.5**	**$ 751.0**	**$ 772.8**	**$ 715.5**	**$ 2,935.8**
Operating income (loss)	**64.8**	**207.3**	**128.2**	**(15.7)**	**384.6**
Income (loss) before income taxes	**(5.9)**	**284.6**	**63.5**	**(51.0)**	**291.2**
Net income (loss) attributable to QEP	**(4.3)**	**178.4**	**37.3**	**(52.0)**	**159.4**
Non-recurring operating income (loss) [1]	**(0.2)**	**100.2**	**9.0**	**(99.0)**	**10.0**
Per share information attributable to QEP					
Basic EPS attributable to QEP	**$ (0.02)**	**$ 0.99**	**$ 0.21**	**$ (0.29)**	**$ 0.89**
Diluted EPS attributable to QEP	**(0.02)**	**0.99**	**0.21**	**(0.29)**	**0.89**
2012					
Revenues	$ 603.2	$ 499.3	$ 542.4	$ 704.9	$ 2,349.8
Operating income (loss)	49.5	(55.5)	(12.6)	(114.7)	(133.3)
Income (loss) before income taxes	244.7	0.3	(4.4)	(42.1)	198.5
Net income (loss) attributable to QEP	155.2	(0.7)	(3.1)	(23.1)	128.3
Non-recurring operating income (loss) [1]	(5.0)	(55.4)	(9.0)	(62.4)	(131.8)
Per share information attributable to QEP					
Basic EPS from continuing operations	$ 0.87	$ —	$ (0.02)	$ (0.13)	$ 0.72
Basic EPS attributable to QEP	0.87	—	(0.02)	(0.13)	0.72

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

Note 17 - 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,	
	2013	2012
	(in millions)	
Proved properties	**$ 11,571.4**	$ 10,234.3
Unproved properties, net	**665.1**	937.9
Total proved and unproved properties	**12,236.5**	11,172.2
Accumulated depreciation, depletion and amortization	**(4,930.9)**	(4,258.1)
Net capitalized costs	**$ 7,305.6**	$ 6,914.1

Costs Incurred
The costs incurred in oil and gas exploration and development activities are displayed in the table below. Development costs are net of the change in accrued capital costs for $21.4 million and ARO additions and revisions of $17.2 million during the year ended December 31, 2013. The costs incurred to advance the development of reserves that were classified as proved undeveloped were approximately $645.9 million in 2013, $513.0 million in 2012, and $533.6 million in 2011.

	Year Ended December 31,		
	2013	2012	2011
	(in millions)		
Property acquisitions			
Unproved	**$ 9.3**	$ 692.6	$ 48.0
Proved	**31.6**	714.4	0.1
Total property acquisitions	**40.9**	1,407.0	48.1
Exploration (capitalized and expensed)	**14.6**	14.3	36.5
Development	**1,440.8**	1,310.0	1,267.8
Total costs incurred	**$ 1,496.3**	$ 2,731.3	$ 1,352.4

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

	Year Ended December 31,		
	2013	2012	2011
	(in millions)		
Revenues [(1)]	**$ 1,901.2**	$ 1,393.4	$ 1,703.4
Production costs	**583.3**	501.1	433.3
Exploration expenses	**11.9**	11.2	10.5
Depreciation, depletion and amortization	**954.2**	838.4	707.4
Impairment	**93.0**	133.0	218.2
Total expenses	**1,642.4**	1,483.7	1,369.4
Income (loss) before income taxes	**258.8**	(90.3)	334.0
Income tax benefit (expense)	**(96.3)**	33.6	(119.0)
Results of operations from producing activities excluding allocated corporate overhead and interest expenses	**$ 162.5**	$ (56.7)	$ 215.0

(1) Revenue for the year ended December 31, 2011, reflect the impact of QEP's settled derivative contracts which during the years ended December 31, 2013 and 2012, are reflected below operating income (loss) on the Consolidated Statements of Operations. See Note 7 - Derivative Contracts.

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., 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, 2013, are scheduled to be developed within five years from the date such locations were initially disclosed as proved undeveloped reserves, except for 120 Bcfe located within the northern portion of the Company's Pinedale Anticline leasehold in western Wyoming. Long-term development of gas reserves in the Pinedale Anticline Project Area (PAPA) 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 defined in the PAPA. The ROD contains additional requirements and restrictions on the sequence of development of the PAPA, which requires the Company to develop its leasehold from the south to the north. These restrictions result in protracted, phased development of the PAPA that is beyond the control of the Company. The Company has an ongoing development plan for the PAPA and the financial capability to continue development in the manner estimated.

As of December 31, 2013, 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, 2011, 2012 and 2013 are as follows:

	Gas	Oil	NGL	Total
	(Bcf)	(MMbbl)	(MMbbl)	(Bcfe)
Balance at December 31, 2010	2,612.9	52.3	17.4	3,030.7
Revisions of previous estimates[6]	(270.1)	1.7	39.3	(23.5)
Extensions and discoveries [7]	641.9	17.4	22.6	881.6
Purchase of reserves in place	1.9	—	—	2.1
Sale of reserves in place	(0.8)	(0.2)	—	(1.9)
Production	(236.4)	(3.7)	(2.7)	(275.2)
Balance at December 31, 2011	2,749.4	67.5	76.6	3,613.8
Revisions of previous estimates [3]	(240.6)	(1.5)	0.7	(244.8)
Extensions and discoveries [4]	330.6	17.3	23.0	572.5
Purchase of reserves in place [5]	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 [1]	**(288.3)**	**1.3**	**(8.0)**	**(328.5)**
Extensions and discoveries [2]	**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**
Proved developed reserves				
Balance at December 31, 2010	1,404.8	25.1	9.3	1,611.5
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**
Proved undeveloped reserves				
Balance at December 31, 2010	1,208.1	27.2	8.0	1,419.2
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**

(1) 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.

(2) 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.

(3) Revisions of previous estimates in 2012 include negative impacts due to 80.0 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.

(4) 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 Legacy 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.

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

(6) Revisions of previous estimates in 2011 include 173.7 Bcfe negative impact due to performance revisions offset by 150.2 Bcfe positive impact from other revisions. The 173.7 Bcfe performance revisions were due to the reduction of gas volumes of 209.8 Bcf, partially offset by an increase in NGL volumes of 33.2 MMbbls, which is included in other revisions. The primary reason for the increase in the NGL volumes, or 31.8 MMbbls, relates to the completion of the Blacks Fork II plant and the fee-based processing agreement entered into between QEP Energy and QEP Field Services for QEP Energy's Pinedale production, offset by a reduction in the dry gas reserve related to shrink of about 59.6 Bcf. The remaining performance related reduction in the gas reserves was primarily related to the removal of certain PUD locations in the Haynesville/Cotton Valley area to recognize the 80-acre increased density development plan.

(7) Extensions and discoveries increased proved reserves by 881.6 Bcfe, primarily related to extensions and discoveries at the Haynesville/Cotton Valley area (358.8 Bcfe), Uinta Basin area (189.1 Bcfe) and Pinedale Anticline area (161.2 Bcfe). All of these extensions and discoveries related to new well completions and associated new PUD locations. Estimates of the quantity of proved reserves from the Company's Pinedale Anticline leasehold in western Wyoming have changed substantially over time as a result of numerous factors including, but not limited to, additional development drilling activity, producing well performance and the development and application of reliable technologies. The continued analysis of new data has led to progressive increases in estimates of original gas-in-place at Pinedale and to a better understanding of the appropriate well density to maximize the economic recovery of the in-place volumes. With the application of the amendments of ASC 932 in ASU 2010-03, reserves associated with Pinedale increased density drilling are included in extensions and discoveries for the years ended December 31, 2011 and 2010, because each new well drilled recovers incremental reserves that would otherwise be unrecoverable.

Standardized Measure of Future Net Cash Flows Relating to Proved Reserves

Future net cash flows were calculated at December 31, 2013, 2012 and 2011, 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 2013, 2012 and 2011, 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,		
	2013	2012	2011
Average benchmark price per unit:			
Gas price (per MMbtu)	**$ 3.67**	$ 2.76	$ 4.12
Oil price (per Bbl)	**96.94**	94.71	96.19

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 $852.6 million in 2014, $1,183.8 million in 2015 and $1,094.4 million in 2016.

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

	Year Ended December 31,		
	2013	2012	2011
	(in millions)		
Future cash inflows	**$ 24,805.7**	$ 18,200.2	$ 18,300.6
Future production costs	**(8,400.3)**	(5,027.2)	(4,276.1)
Future development costs	**(4,056.7)**	(3,927.3)	(3,250.0)
Future income tax expenses	**(3,284.6)**	(2,269.0)	(2,837.1)
	9,064.1	6,976.7	7,937.4
10% annual discount for estimated timing of net cash flows	**(4,680.2)**	(3,942.0)	(4,411.8)
Standardized measure of discounted future net cash flows	**$ 4,383.9**	$ 3,034.7	$ 3,525.6

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

	Year Ended December 31,		
	2013	2012	2011
	(in millions)		
Balance at January 1,	**$ 3,034.7**	$ 3,525.6	$ 2,705.6
Sales of gas, oil and NGL produced during the period, net of production costs	**(1,317.9)**	(892.3)	(1,779.9)
Net change in sales prices and in production (lifting) costs related to future production	**1,236.3**	(2,083.5)	1,472.5
Net change due to extensions, discoveries and improved recovery	**2,230.7**	948.5	1,806.4
Net change due to revisions of quantity estimates	**(709.6)**	(387.8)	(48.2)
Changes due to purchases of reserves in place	**36.8**	831.4	0.1
Changes due to sales of reserves in place	**(73.2)**	—	(8.0)
Previously estimated development costs incurred during the period	**722.7**	513.0	533.6
Changes in estimated future development costs	**(596.5)**	(209.3)	(1,110.4)
Accretion of discount	**402.2**	499.4	355.4
Net change in income taxes	**(601.7)**	273.6	(411.4)
Other	**19.4**	16.1	9.9
Net change	**1,349.2**	(490.9)	820.0
Balance at December 31,	**$ 4,383.9**	$ 3,034.7	$ 3,525.6

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

As disclosed in the Company's Current Report on Form 8-K, filed with the SEC on November 17, 2011, and its Current Report on Form 8-K/A, filed with the SEC on February 28, 2012, the Company changed its independent registered public accountants effective for the fiscal year ended December 31, 2012. There were no disagreements with QEP's former independent registered public accounting firm.

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, 2013. Based on such evaluation, such officers have concluded that, as of December 31, 2013, 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 reports filed or submitted by the Company 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, 2013, 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.

As of December 31, 2013, management assessed the effectiveness of our internal control over financial reporting based on the criteria for effective internal control over financial reporting established in *Internal Control—Integrated Framework*, issued by the Committee of Sponsoring Organizations of the Treadway Commission in 1992. Based on the assessment, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2013, based on those criteria. 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, 2013, 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

Amendment of the Executive Severance Compensation Plan

On February 23, 2014, QEP's Board of Directors approved revisions to its executive severance plan, now named the QEP Resources, Inc. Executive Severance Compensation Plan - CIC (the CIC Severance Plan). The revisions are effective immediately. The CIC Severance Plan amends the QEP Resources, Inc. Executive Severance Plan adopted in February 2012 and amended in May 2012 (the Original Plan), to (i) rename the Original Plan the "QEP Resources, Inc. Executive Severance Plan - CIC" to clarify that it applies only in the event of a change in control and to distinguish it from the QEP Resources, Inc. Basic Severance Compensation Plan (the Basic Severance Plan); (ii) remove references in the Original Plan relating to Questar Corporation benefits arrangements, as such references are no longer relevant to the operation of the plan; (iii) include a more flexible provision relating to performance-based long-term incentive awards that applies whether the awards are settled in cash or stock; (iv) clarify that severance under the CIC Severance Plan is (a) payable if a participant is terminated upon consummation of a change in control or at any time during the third anniversary of the change in control, and (b) not payable if a participant's employment is terminated by the Company due to disability; (v) conform the Original Plan to the Basic Severance Plan by (a) adding a requirement that the Company pay the participant's attorneys' fees if the participant brings a legal proceeding to enforce his or her rights under the CIC Severance Plan and prevails on at least one material claim, and (b) clarifying the mechanism that applies if the participant's exposure to the tax is miscalculated, which includes an indemnification by the Company of the participant for expenses incurred in connection with any related tax dispute.

Like the Original Plan, the CIC Severance Plan establishes two tiers of participants with different compensation in the event of termination following a change in control. Tier 1 Participants include the chief executive officer, chief financial officer and any other officer so designated by the Company's Board of Directors. Tier 2 Participants include all other officers of the Company. In the event of termination of employment following a change in control, Tier 1 Participants will receive three times the sum of their base salary and three-year average annual bonus, and Tier 2 Participants will receive two times the sum of their base salary and three-year average annual bonus. All participants will receive prorated bonuses under the applicable annual cash incentive plan in respect of the year in which the change in control occurs based on satisfaction of the performance goals achieved for such year. Additionally, following termination of employment following a change in control, participants shall receive a payment in cash or shares of Company common stock, as applicable, for each grant of performance share units held by the participant as of the termination date, based on the level of achievement of the applicable performance goals as of immediately prior to the change in control; and accelerated vesting (in full) of all stock options, stock appreciation rights, restricted stock grants and other equity incentive awards (other than any performance share units), with stock options remaining exercisable until the earlier of one year post-termination or their original expiration date. Finally, health and welfare benefits continue for three years for Tier 1 Participants and for two years for Tier 2 Participants. If a termination would entitle a participant to severance payments and benefits under both the Basic Severance Plan and the CIC Severance Plan, severance pay and benefits will be provided only under the CIC Severance Plan.

The foregoing description of the CIC Severance Plan is not complete and is qualified in its entirety by reference to the text of the full CIC Severance Plan, which is attached as Exhibit 10.9 to this Form 10-K and is incorporated herein by reference.

Completion of Acquisition of Assets

On February 24, 2014, QEP, through its wholly owned subsidiary QEP Energy, closed its previously announced transaction with Enervest Holding, L.P., Enervest Energy Institutional Fund XII-A, L.P., Enervest Energy Institutional Fund XII-WIB, L.P., and Enervest Energy Institutional Fund XII-WIC, L.P. (the Sellers). QEP acquired certain oil and natural gas interests (the Acquired Properties) in Martin and Andrews counties in west Texas pursuant to the related purchase and sale agreement with the Seller. The aggregate consideration paid to the Sellers for the acquisition was approximately $950.0 million (the Purchase Price). The Purchase Price is subject to final purchase price adjustments to be determined based on an effective date of November 1, 2013.

The Acquired Properties consist of approximately 26,500 net acres of producing and undeveloped oil and gas properties and approximately 260 vertical producing wells in the Permian Basin. The Acquired Properties have estimated aggregate net proved reserves of approximately 47 MMBoe based upon internal estimates.

The Purchase Price was funded with cash on hand, $300.0 million from the Company's expanded Term Loan and approximately $600.0 million from its revolving credit facility. The purchase and sale agreement will be filed with the Company's Quarterly Report on Form 10-Q for the quarter ending March 31, 2014.

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 to be held on May 13, 2014, which will be filed with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2013 (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 No. 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 No. 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 No. 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 February 14, 2013. (Incorporated by reference to Exhibit No. 3.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on February 15, 2013.)
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 No. 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 No. 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 No. 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 QEP Resources, Inc.'s Current Report on Form 8-K filed with the Securities and Exchange Commission on August 16, 2013.)
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 No. 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 QEP Resources, Inc.'s Current Report on Form 8-K filed with the Securities and Exchange Commission on August 16, 2013.)
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 No. 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 No. 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 No. 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 (Incorporated by reference to Exhibit No. 10.4 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 16, 2010.)
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 No. 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 No. 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.
10.10+	QEP Resources, Inc. Amended Deferred Compensation Wrap Plan adopted January 28, 2013. (Incorporated by reference to Exhibit No. 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on January 31, 2013.)
10.11+	QEP Resources, Inc. Supplemental Executive Retirement Plan adopted June 12, 2010 (Incorporated by reference to Exhibit No. 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 No. 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 No. 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 No. 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 No. 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 No. 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 No. 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 No. 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 No. 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 No. 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 No. 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 No. 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 No. 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 No. 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 QEP Resources, Inc.'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 QEP Resources, Inc'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 QEP Resources, Inc'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 QEP Resources, Inc'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 No. 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.)
12.1*	Ratio of earnings to fixed charges.
16.1	Letter from Ernst & Young LLP to the Securities and Exchange Commission dated February 28, 2012 regarding change in Company's Certifying Accountant. (Incorporated by reference to Exhibit No. 16.1 to the Company's Current Report on Form 8-K/A filed with the Securities and Exchange Commission on February 28, 2012.)
21.1*	Subsidiaries of the Company.
23.1*	Consent of Independent Registered Public Accounting Firm - PricewaterhouseCoopers LLP.
23.2*	Consent of Independent Registered Public Accounting Firm - Ernst & Young LLP.
23.3*	Consent of Independent Petroleum Engineers and Geologists - Ryder Scott Company, L.P.
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, Treasurer and Chief Accounting 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, Treasurer and Chief Accounting 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.
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, 2013				
Allowance for bad debts	**$ 2.8**	**$ 3.5**	**$ (1.2)**	**$ 5.1**
Year ended December 31, 2012				
Allowance for bad debts	1.7	1.4	(0.3)	2.8
Year ended December 31, 2011				
Allowance for bad debts	2.3	0.2	(0.8)	1.7

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 25, 2014.

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 and on February 25, 2014.

/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, Chief Financial Officer, Treasurer, and Chief Accounting Officer (Principal Financial and 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
*Thomas C. O’Connor	Director
*William L. Thacker III	Director
February 25, 2014	*By /s/ Charles B. Stanley Charles B. Stanley, Attorney in Fact

Exhibit 10.9

QEP RESOURCES, INC.

EXECUTIVE SEVERANCE COMPENSATION PLAN – CIC

QEP RESOURCES, INC.
EXECUTIVE SEVERANCE COMPENSATION PLAN – CIC
As Amended and Restated as of February 23, 2014

ARTICLE I
INTRODUCTION AND ESTABLISHMENT OF PLAN

The Board of Directors of QEP Resources, Inc. recognizes that, as is the case with many publicly held corporations, the possibility of a Change in Control exists. This possibility, and the uncertainty it creates with executives, may be detrimental to the Company and its shareholders if executives are distracted and/or leave the Company.

The Board considers the avoidance of such loss and distraction to be essential to protecting and enhancing the best interests of the Company and its shareholders. The Board also believes that when a Change in Control is perceived as imminent, or is occurring, the Board should be able to receive and rely on disinterested service from executive employees regarding the best interests of the Company and its shareholders without concern that the executive employees might be distracted or concerned by their personal uncertainties and risks created by the perception of an imminent or occurring Change in Control.

In addition, the Board believes that it is consistent with the Company's employment practices and policies and in the best interests of the Company and its shareholders to compensate its executive employees whose employment terminates in connection with or following a Change in Control.

Accordingly, the Board has determined that appropriate steps should be taken to assure the Company and its Affiliates of the executive employees' continued employment and attention and dedication to duty, and to seek to ensure the availability of their continued service, notwithstanding the possibility, threat or occurrence of a Change in Control.

In order to fulfill the above purposes, the Board hereby adopts this QEP Resources, Inc. Executive Severance Compensation Plan – CIC, as amended and restated (the "Plan") by consent dated February 23, 2014, to be effective immediately (the "Effective Date").

ARTICLE II DEFINITIONS

As used herein, the following words and phrases shall have the following respective meanings unless the context clearly indicates otherwise.

(a) Affiliate. 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 Section 409A of the Code, or any entity otherwise designated as an Affiliate by the Company.

(b) Annual Cash Incentive Plan. Any annual incentive plan, program or arrangement offered by an Employer pursuant to which a Participant is eligible to receive a cash award, subject in whole or in part to the achievement of performance goals over a period of no more than one year.

(c) Annual Base Salary. A Participant's gross annual base salary in effect immediately prior to a Change in Control.

(d) Average Annual Bonus Amount. The average of the annual bonuses a Participant actually received under the Annual Cash Incentive Plans.

(e) Basic Severance Plan. The QEP Resources, Inc. Basic Executive Severance Plan.

(f) Board. The Board of Directors of the Company.

(g) Cash Incentive Plan. Any long-term incentive plan, program or arrangement offered by an Employer pursuant to which a Participant is eligible to receive a cash award, subject in whole or in part to the achievement of performance goals over a period of more than one year, including without limitation the QEP Resources, Inc. Cash Incentive Plan.

(h) Cause. Cause means the Participant's: (i) willful and continued failure to perform substantially the Participant's duties with an Employer (other than any such failure resulting from incapacity due to physical or mental illness), following written demand for substantial performance delivered to the Participant by the Board or the Chief Executive Officer of the Company; or (ii) willful engagement in conduct that is materially injurious to an Employer. For purposes of this definition, no act or failure to act on the part of the Participant shall be considered "willful" unless it is done, or omitted to be done, by the Participant without reasonable belief that the Participant's action or omission was in the best interests of the Participant's Employer. The Company, acting through the Board, must notify the Participant in writing that the Participant's employment is being terminated for "Cause". The notice shall include a list of the factual findings used to sustain the judgment that the Participant's employment is being terminated for "Cause".

(i) Change in Control. A Change in Control of the Company 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.

(j) Code. The Internal Revenue Code of 1986, as amended from time to time.

(k) Company. QEP Resources, Inc. and any successor to such entity.

(l) Compensation. For purposes of the Plan, "Compensation" means (i) with respect to any Participant who participates in the Retirement Plan, such Participant's remuneration taken into account for purposes of calculating the retirement benefit thereunder, and, (ii) with respect to any Participant who participates in the SERP, such Participant's remuneration taken into account for purposes of calculating the retirement benefit thereunder.

(m) Date of Termination. The date on which a Participant ceases to be an Employee of an Employer as a result of a Separation from Service.

(n) Disability. A condition resulting in the Participant's receipt of payments for disability under the QEP Resources, Inc. Long-term Disability Plan or any plan providing similar long-term disability benefits sponsored by the Company or an Affiliate.

(o) Eligible Employee. Any officer of any Employer.

(p) Employer. With respect to any Participant, the Company and any Affiliate that participates in the Plan pursuant to Article VIII hereof which employs the Participant.

(q) ERISA. The Employee Retirement Income Security Act of 1974, as amended from time to time.

(r) Good Reason. Good Reason means any of the following events or conditions that occur without the Participant's written consent, and that remain in effect after notice has been provided by the Participant to the Company of such event or condition and the expiration of a 30 day cure period: (i) a material diminution in the Participant's Annual Base Salary, target bonus opportunity under any Annual Cash Incentive Plan or long-term incentive award opportunity under any Cash Incentive Plan or Stock Incentive Plan; (ii) a material diminution in the Participant's authority, duties, or responsibilities; (iii) a material diminution in the authority, duties, or responsibilities of the supervisor to whom the Participant is required to report, including a requirement that a Participant report to a corporate officer or employee instead of reporting directly to the Board; (iv) a material diminution in the budget over which the Participant retains authority; (v) a material change in the geographic location at which the Participant performs services; or (vi) any other action or inaction that constitutes a material breach by an Employer of the Participant's employment agreement (if any). The Participant's notification to the Company must be in writing and must occur within a reasonable period of time, not to exceed 90 days, following the initial existence of the relevant event or condition.

(s) Participant. An individual who is designated as such pursuant to Section 3.1.

(t) Performance Share Units. Performance share units granted under the Cash Incentive Plan which settle only in cash, and any similar award granted under a Stock Incentive Plan which settles, or may settle, wholly or partially in shares of the Company's common stock, in each case based on the achievement of performance goals over a period of more than one year.

(u) Plan Administrator. The Compensation Committee of the Board.

(v) Retirement Plan. The QEP Resources, Inc. Retirement Plan, as amended or restated from time to time, or any successor plan.

(w) Separation Benefits. The payments and benefits described in Article V and Article VI that are provided to Participants under the Plan pursuant to Section 4.1.

(x) Separation from Service. 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 the 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.

(y) SERP. The QEP Resources, Inc. Supplemental Executive Retirement Plan, as amended or restated from time to time, or any successor plan.

(z) Stock Incentive Plan. Any incentive plan offered by the Company pursuant to which upon or following vesting or exercise, as applicable, a Participant is entitled to receive shares of the Company’s common stock, including without limitation the QEP Resources, Inc. 2010 Stock Incentive Plan.

(aa) Tier 1 Participant. A Participant who is either the Chief Executive Officer or Chief Financial Officer of the Company and any other person so designated by the Board.

(ab) Tier 2 Participant. Each Participant who is not a Tier 1 Participant.

(ac) Year. The calendar year or other applicable performance period under any Annual Cash Incentive Plan.

ARTICLE III ELIGIBILITY

3.1 Participation. The Board shall, in its sole discretion, select from the group of Eligible Employees those individuals who may participate in the Plan. Any Eligible Employee selected for participation shall become a Participant upon written notification by the Board (or its designee) to such Eligible Employee of his or her participation in the Plan.

3.2 Termination of Participation. Prior to the time that the Board knows or should know that a Change in Control is under consideration, is being negotiated or is otherwise contemplated, a Participant shall continue to participate in the Plan at the sole discretion of the Board, which may terminate the individual's participation in the Plan for any reason. In the event that a Participant ceases to be an Eligible Employee (other than by virtue of an action by the Employer which constitutes Good Reason) and is not entitled to a Separation Benefit as of the date such Participant ceases to be an Eligible Employee (including by virtue thereof), such Participant shall cease to be a Participant in the Plan on such date. Notwithstanding anything to the contrary in the Plan, a Participant entitled to Separation Benefits under the Plan shall remain a Participant in the Plan until the full Separation Benefits and any other amounts payable under the Plan have been paid or provided.

ARTICLE IV
ENTITLEMENT TO BENEFITS

4.1 Separations from Service That Give Rise to Separation Benefits Under The Plan. A Participant shall be entitled to Separation Benefits if, upon a Change in Control or within the three years thereafter, the Participant incurs a Separation from Service from an Employer that is (a) initiated by the Participant's Employer for any reason other than Cause or Disability or (b) initiated by the Participant for Good Reason within 60 days following the expiration of the cure period afforded the Company to rectify the condition giving rise to Good Reason.

4.2. No Duplication of Severance Benefits. Notwithstanding anything to the contrary in the Plan, in no event shall any Participant be eligible for both Separation Benefits hereunder and separation benefits under the Basic Severance Plan. In the event that a Participant incurs a Separation from Service that entitles such Participant to Separation Benefits under the Plan, such participant shall be deemed to have ceased to be eligible to participate in the Basic Severance Plan immediately prior to the Date of Termination in accordance with the terms thereof.

ARTICLE V
SEPARATION BENEFITS

5.1 Separation Benefits; General. If a Participant's employment is terminated in circumstances entitling the participant to Separation Benefits pursuant to Section 4.1, the Company shall provide to such Participant the cash payment set forth in Section 5.2 below, the bonuses set forth in Section 5.3 below, the enhanced retirement benefits set forth in Section 5.4 below and the continued welfare benefits as set forth in Section 5.5 below.

5.2 Cash Severance. Each Participant entitled to Separation Benefits shall receive cash severance equal to the aggregate of the following amounts:

(a) For a Tier 1 Participant, an amount equal to three times the Participant's Annual Base Salary plus three-times the Participant's three-year Average Annual Bonus Amount; and

(b) For a Tier 2 Participant, an amount equal to two times the Participant's Annual Base Salary plus two-times the Participant's three-year Average Annual Bonus Amount.

All cash payments required by this Section 5.2 shall be paid within 10 calendar days of the Participant's Date of Termination; subject, however, to any payment delay required by Section 5.8(b).

5.3 Bonus Amounts. Each Participant entitled to Separation Benefits shall receive the following payments:

(a) the bonus the Participant would have received in respect of the Year in which the Change in Control occurs under the applicable Annual Cash Incentive Plan had the Change in Control not occurred, based on the level of satisfaction of the performance goals that is achieved for such Year (or, if the Participant's performance goals have not been established by the date that the Change in Control occurs, then, solely for purposes of this clause (i), the Change in Control shall be deemed to have occurred on December 31 of the immediately preceding Year), multiplied by (ii) (A) the number of full months of Participant's continuous service with the Employer during such Year (with each month for which at least one day has elapsed counting as a full month), divided by (B) the number of full months in such Year. In addition, if the Date of Termination occurs after the end of a Year but before the Participant's bonus under the applicable Annual Cash Incentive Plan in respect of such Year has been paid, the Participant shall be eligible to receive such bonus, without proration; and

(b) a payment in cash or shares of Company common stock, as applicable, for each grant of Performance Share Units held by the Participant as of the Date of Termination, based on the level of achievement of the applicable performance goals as of immediately prior to the Change in Control, without proration. In addition, if the Date of Termination occurs after the end of a Performance Share Unit performance period but before the Participant has received payment in respect of such Performance Share Units, the Participant shall be eligible to receive such payment, also without proration.

The payments required by this Section 5.3 each shall be paid in a lump sum within 60 days following the end of the year in which the Date of Termination occurs; subject, however, to any payment delay required by Section 5.8(b).

5.4 Enhanced Retirement Benefits. Each Participant entitled to Separation Benefits shall receive an enhanced retirement benefit under the Retirement Plan and/or the SERP, to the extent that the Participant is a participant in such plan(s) as of the Date of Termination, as follows:

(a) Vested Participants. Participants who have an accrued vested benefit under either the Retirement Plan or both the Retirement Plan and the SERP as of the Date of Termination shall be entitled to an enhanced retirement benefit under the Plan in an amount equal to the excess of (i) the benefit the Participant would have accrued under the Retirement Plan and the SERP (if participating) as of the Date of Termination calculated as if (A) the Participant had been credited with two additional years of benefit service under the Retirement Plan and the SERP (if participating) as of the Date of Termination, and (B) the Participant's Compensation under the Retirement Plan and the SERP (if participating) for each additional year of such service had been equal to the Participant's Compensation for the last full Year prior to the Date of Termination, over (ii) the actual benefit accrued under the Retirement Plan and the SERP (if participating) as of the Date of Termination.

(b) Payment of Enhanced Retirement Benefits. Any enhanced retirement benefit to which a Participant may be entitled under paragraph (a) above shall be paid in a single lump sum within 30 calendar days of the Date of Termination; subject, however, to any payment delay required by Section 5.8(b). The lump-sum payment shall be equal to (i) the present value of the applicable enhanced retirement benefit on the Date of Termination, calculated using a standard mortality table referred to as the 1983 Group Annuity Mortality table and an interest rate equal to 80 percent of the average of the IRS 30-year Treasury Securities Rates for the six-month period preceding the participant's Date of Termination, plus (ii) interest on such amount, credited monthly from the Date of Termination through the date of payment (taking into account any delay required by Section 5.8(b)), using the appropriate 30-year Treasury bond rate quoted in the Wall Street Journal on the first business day of each month. The appropriate 30-year Treasury bond shall be the bond that has the closest maturity date (by month) preceding the month in which interest is to be credited.

(c) Ineligible to Participate in Retirement Plan. In no event shall a Participant be entitled to any benefit under this Section 5.4 if he or she is not a participant in the Retirement Plan and/or the SERP as of the Date of Termination.

5.5 Continued Welfare Benefits. For a period of three years in the case of a Tier 1 participant, and two years in the case of a Tier 2 Participant, following the Participant's Date of Termination, the Participant and his or her family shall be provided without cost medical, dental, accidental death and dismemberment, and life insurance benefits that are the same as, or substantially similar to, the benefits that would have been provided by the Company, an Affiliate or any successor during such period had the Participant's employment not been terminated. Some or all of the benefits required by this Section may be provided through the payment or reimbursement of premiums incurred for similar coverage procured by the Company, an Affiliate or any successor on the Participant's behalf or by the Participant, through the payment of COBRA premiums, or pursuant to the terms and conditions of the Company's retiree health insurance program, if applicable, in each case as determined by the Company in its sole discretion and subject to Sections 5.8 and 11.8 below.

5.6 Stock Option and Stock Appreciation Right Benefits. Notwithstanding any shorter period to the contrary in any agreement between a Participant and the Company evidencing a grant of stock options or stock appreciation rights, a Participant entitled to Separation Benefits shall have a minimum of one year (but not beyond the date when the options or rights would otherwise expire by their terms) following the Date of Termination in which to exercise any vested stock options and stock appreciation rights outstanding as of the Change in Control. Nothing in this Section 5.6, however, shall require the Company to continue in effect any stock option or stock appreciation right following a Change in Control, if, pursuant to the terms of the Change in Control, the Participant will receive automatically (on or within a reasonable time following the Change in Control), in cash or marketable securities, the intrinsic value of such awards as of the date of the Change in Control.

5.7 Other Benefits Payable. To the extent not theretofore paid or provided, the Company shall timely pay or provide (or cause to be paid or provided) to a Participant entitled to Separation Benefits, any other amounts or benefits required to be paid or provided to the Participant or which the Participant is eligible to receive under any plan, program, policy or practice or contract or agreement of an Employer. Notwithstanding the foregoing, if a Participant is entitled to Separation Benefits under the Plan, the Participant shall not also be entitled to severance benefits under any employment agreement or other severance pay plan or policy of the Company. Thus, by way of example and not by way of limitation, benefits earned under the Retirement Plan, the SERP, and the QEP Resources, Inc. Deferred Compensation Wrap Plan, in each case as amended from time to time, or any successor plans, shall be unaffected by a Participant's receipt of Separation Benefits, and shall continue to be payable solely in accordance with the relevant terms of those plans, but any severance benefits to which a Participant otherwise may be entitled under an employment agreement or severance plan, if any, shall not apply if the Participant is entitled to receive Separation Benefits under the Plan. In addition, Separation Benefits under the Plan shall also be reduced by any amounts that are paid under any incentive compensation plans of the Employer that are contingent on the Participant's termination of employment or a change in control.

5.8 Code Section 409A; Specified Employees.

(a) Subject to Section 5.8(b), to the extent permitted under Code Section 409A, any separate payment or benefit under the Plan or otherwise shall not be deemed "nonqualified deferred compensation" subject to Code Section 409A, to the extent provided in the exceptions in Treasury Regulation Section 1.409A-1(b)(4), Section 1.409A-1(b)(9) or any other applicable exception or provision of Code Section 409A.

(b) Notwithstanding anything to the contrary in the Plan, no compensation or benefits shall be paid to a Participant during the six-month period following his or her Date of Termination to the extent that the Company determines that the Participant is a "specified employee" as of the Date of Termination and that paying such amounts at the time or times indicated in the Plan would result in tax penalties to the Participant under Code Section 409A. 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 six-month period (or such earlier date upon which such amount can be paid under Code Section 409A without being subject to tax penalties, including as a result of the Participant's death), the Company shall pay to the Participant a lump- sum amount equal to the cumulative amount that would have otherwise been payable to the Participant during such six-month period.

(c) To the extent that Section 5.5 requires the Company, partially or wholly, to subsidize any continuation of health insurance benefits following the Participant's Date of Termination:

(i) If such continued health insurance benefits are to be provided through third-party insurance maintained by the Company under the Company's benefit plans in a manner that causes such health insurance benefits to be exempt from the application of Code Section 409A under Treasury Regulation Section 1.409A-1(a)(5), the Company shall pay or reimburse such premiums in accordance with the terms of the Plan, subject to Section 6.8(d); provided, however, that if, during the period of health insurance benefits continuation coverage (the "Health Benefits Continuation Period"), any plan pursuant to which such health insurance benefits are provided is not, or ceases prior to the expiration of the Health Benefits Continuation Period to be, exempt from the application of Code Section 409A under Treasury Regulation Section 1.409A-1(a)(5), then an amount equal to each remaining premium payments shall thereafter be paid to the Participant as currently taxable compensation in substantially equal monthly installments over the remainder of the Health Benefits Continuation Period , accompanied by any additional amounts necessary to offset the taxable nature of such benefit to the extent such amounts are either exempt from or compliant with the requirements of Code Section 409A; or

(ii) If such continued health insurance benefits are to be provided in whole or in part through a self-funded plan maintained by the Company, the benefits of which are not fully-insured by a third-party insurer:

(A) To the greatest extent applicable, such health insurance benefits shall be construed to satisfy the exemption from Code Section 409A pursuant to Treasury Regulation Section 1.409A-1(b)(9)(v)(B), and

(B) To the extent such health insurance benefits do not satisfy such exemption and/or they do extend beyond the continuation period under COBRA, determined as of the Participant's Date of Termination, the Company shall reimburse the premiums relating to such health insurance benefits in accordance with Section 5.8(d).

(d) To the extent that any payments or reimbursements provided to the Participant under the Plan 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 associated expense was incurred. The amount of any expense reimbursements that constitute compensation in one year shall not affect the amount of expense reimbursements constituting compensation that are eligible for reimbursement in any subsequent year, and the Participant's right to such reimbursement of any such expenses shall not be subject to liquidation or exchange for any other benefit.

ARTICLE VI
EQUITY INCENTIVE BENEFITS

All of a Participant's stock options, stock appreciation rights, restricted stock awards, and other equity incentive awards (other than any Performance Share Units) granted pursuant to a Stock Incentive Plan and then held by the Participant, shall vest in full immediately prior to a Change in Control.

ARTICLE VII
SPECIAL TAX PROVISIONS

7.1 Participant Choice. Except as set forth below, in the event it shall be determined that any payment or distribution by an Employer to or for the benefit of a Participant pursuant to the terms of the Plan (a "Payment") would be subject to the excise tax imposed by Section 4999 of the Code or any interest or penalties would be incurred by the Participant with respect to such excise tax (such excise tax, together with any such interest and penalties, are hereinafter collectively referred to as the "Excise Tax"), then the Participant shall be entitled to elect either to (a) receive the full amount of the Payment and be solely responsible for the payment of any Excise Tax due on such payment, or (b) have the payments, distributions or benefits owing to the Participant under the Plan "capped" or limited to the maximum dollar amount that can be paid from the Plan without the Participant's incurring Excise Tax (the "Capped Amount").

7.2 Determination of Capped Amount. Subject to the provisions of Section 7.3, all determinations required to be made under this Article VII, including computation of the Capped Amount, and the assumptions to be utilized in arriving at such determination, shall be made by a nationally recognized certified public accounting firm designated by the Company (the "Accounting Firm") which shall provide detailed supporting calculations both to the Company and the Participant within 15 business days after the receipt of notice from the Participant that amounts payable to the Participant could constitute a Payment, or such earlier time as is requested by the Company. In the event that the Accounting Firm is serving as accountant or auditor for the individual, entity or group effecting the Change in Control, the Company shall appoint another nationally recognized accounting firm to make the determinations required hereunder (which accounting firm shall then be referred to as the Accounting Firm hereunder). All fees and expenses of the Accounting Firm shall be borne solely by the Company. Subject to the provisions of Section 7.3 hereof, any determination by the Accounting Firm shall be binding upon the Company and the Participant.

7.3 Overpayment/Underpayment. As a result of the uncertainty in the application of Section 4999 of the Code at the time of the determination by the Accounting Firm pursuant to Section 7.2, it is possible that amounts will have been paid or distributed by the Company to or for the benefit of the Participant pursuant to Section 7.2 that should not have been so paid or distributed (each, an "Overpayment") or that additional amounts which will have not been paid or distributed by the Company to or for the benefit of the Participant pursuant to Section 7.2 could have been so paid or distributed (each, an "Underpayment"), in each case, consistent with the calculation of the Capped Amount pursuant to Section 7.2. In the event that the Accounting Firm, based upon the assertion of a deficiency by the Internal Revenue Service against either the Company or the Participant which the Accounting Firm believes has a high probability of success determines that an Overpayment has been made, any such Overpayment paid or distributed by the Company to or for the benefit of the Participant shall be repaid by the Participant to the Company together with interest at the applicable federal rate provided for in Section 7872(f)(2) of the Code; provided, however, that no such repayment shall be required if and to the extent such deemed repayment would not either reduce the amount on which the Participant is subject to tax under Section 1 and Section 4999 of the Code or generate a refund of such taxes. In the event that the Accounting Firm, based upon controlling precedent or substantial authority, determines that an Underpayment has occurred, any such Underpayment shall be promptly paid by the Company to or for the benefit of the Participant together with interest at the applicable federal rate provided for in Section 7872(f)(2) of the Code.

7.4 Tax Proceedings. In the event that the Participant elects to receive the Capped Amount pursuant to Section 7.1 and a deficiency is later asserted by the Internal Revenue Service due to an alleged Overpayment, the Company shall indemnify and hold the Participant harmless for any costs, expenses, interest, penalties, taxes, attorneys' fees or other amounts (the "Indemnified Amounts") incurred or imposed in connection with any tax contest, audit or litigation of such deficiency; provided, however, that in no event shall the Indemnified Amounts include any portion of the Capped Amount itself or any Excise Tax thereon. Any Indemnified Amounts will be paid directly by the Company or advanced to the Participant by the end of the Participant's taxable year following the taxable year in which the taxes that are the subject of the tax contest, audit or litigation are remitted to the taxing authority, or where as a result of such tax contest, audit or litigation no taxes are remitted, the end of the Participant's taxable year following the taxable year in which the audit is completed or there is a final and non-appealable settlement or other resolution of the contest or litigation.

7.5 Withholding. All payments to the Participant in accordance with the provisions of the Plan shall be subject to applicable withholding of local, state, Federal and foreign taxes, as determined in the sole discretion of the Company.

ARTICLE VIII PARTICIPATING EMPLOYERS

Any Affiliate of the Company may become a participating Employer in the Plan following approval by the Company. The provisions of the Plan shall be fully applicable to the Employees of any such Affiliate who are Participants pursuant to Section 3.1.

ARTICLE IX
SUCCESSOR TO COMPANY

The Plan shall bind any successor of the Company, its assets or its businesses (whether direct or indirect, by purchase, merger, consolidation, separation or otherwise), in the same manner and to the same extent that the Company would be obligated under the Plan if no succession had taken place.

In the case of any transaction in which a successor would not by the foregoing provision or by operation of law be bound by the Plan, the Company shall require such successor expressly and unconditionally to assume and agree to perform the Company's obligations under the Plan, in the same manner and to the same extent that the Company would be required to perform if no such succession had taken place. In the event of a Change in Control in which the successor fails to expressly and unconditionally assume and agree to perform the Company's obligations under the Plan, each Participant in the Plan immediately prior to such Change in Control shall be deemed to have incurred a qualifying Separation from Service under Section 4.1 and shall be entitled to payment of the cash equivalent of all Separation Benefits set forth in Article V as if the day prior to the date of such Change in Control were the Participant's Date of Termination, in the form of a single lump sum within 60 days following the Change in Control.

The term "Company," as used in the Plan, shall mean the Company as hereinbefore defined and any successor or assignee to the business or assets which by reason hereof becomes bound by the Plan.

ARTICLE X
DURATION, AMENDMENT AND TERMINATION

10.1 Duration. If a Change in Control has not occurred, the Plan shall continue indefinitely unless and until terminated by the Board pursuant to Section 10.2, below. If a Change in Control occurs while the Plan is in effect, the Plan shall continue in full force and effect for three years following such Change in Control, and shall then automatically terminate; provided, however, that all Participants who become entitled to Separation Benefits hereunder prior to termination of the Plan shall continue to receive such Separation Benefits notwithstanding any termination of the Plan.

10.2 Amendment or Termination. The Board may amend or terminate the Plan for any reason prior to a Change in Control except that the Plan shall not be terminated or amended to reduce any benefits provided under the Plan at a time when the Board knows or should know that a Change in Control is under consideration, is being negotiated or is otherwise contemplated. In the event of a Change in Control, the Plan shall automatically terminate as set forth in Section 10.1 but may not be amended or prematurely terminated.

10.3 Procedure for Extension, Amendment or Termination. Any amendment or termination of the Plan by the Board in accordance with the foregoing shall be made by action of the Board in accordance with the Company's charter and by-laws and applicable law.

ARTICLE XI MISCELLANEOUS

11.1 Full Settlement. The Company's obligation to make the payments provided for under the Plan and otherwise to perform its obligations hereunder shall not be affected by any set-off, counterclaim, recoupment, defense or other claim, right or action which the Company may have against a Participant or others outside of the Plan. In no event shall a Participant be obligated to seek other employment or take any other action by way of mitigation of the amounts payable to the Participant under any of the provisions of the Plan and such amounts shall not be reduced whether or not the Participant obtains other employment.

11.2 Employment Status. This Plan does not constitute a contract of employment or impose on the Participant or the Participant's Employer any obligation for the Participant to remain an Employee or change the status of the Participant's employment or the policies of the Participant's Employer regarding termination of employment.

11.3 Confidential Information. No Participant shall disclose or divulge to any other person or entity, directly or indirectly, any secret or confidential information, knowledge or data relating to the Company or its Affiliates, or their respective businesses, including but not limited to, (a) practices, policies and/or procedures; (b) trade secrets; (c) customer names; (d) information regarding existing or prospective future business, planning or development; (e) contracts or proposed contracts; (f) financial information; (g) staffing or personnel utilization; (h) salary or wage levels; (i) privileged communications; and (j) other information deemed confidential or proprietary not listed herein which shall have been obtained by the Participant during the Participant's employment by the Participant's Employer and which shall not be or become public knowledge (other than by acts by the Participant or representatives of the Participant in violation of the Plan) (the "Confidential Information"). During and after termination of a Participant's employment with the Company or other Employer, the Participant shall not, without the prior written consent of the Company or as may otherwise be required by law or legal process, communicate or divulge any Confidential Information to anyone other than the Company or its Affiliates. Notwithstanding the foregoing, the use or communication of mental impressions of Confidential Information in a manner that does not directly or indirectly identify the Company and its Affiliates and would not be reasonably expected to materially adversely affect the business of the Company and its Affiliates shall not be a violation of this Section 11.3.

11.4 Applicability of ERISA. The Plan is not intended to be an "employee benefit plan," as defined in Section 3(3) of ERISA, and therefore is intended to not be subject to ERISA. However, if (and only if) the Plan is determined to be such an "employee benefit plan" and therefore subject to ERISA, (i) it is intended to be a plan which is unfunded and maintained primarily for the purpose of providing deferred compensation for a select group of management or highly compensated employees, (ii) the Company shall be the named fiduciary of the Plan, and (iii) Section 11.6 of the Plan shall apply.

11.5 Administration. The Plan Administrator shall have full and complete discretionary authority to administer, construe, and interpret the Plan, to decide all questions of eligibility, to determine the amount, manner and time of payment, and to make all other determinations deemed necessary or advisable for the Plan. The Plan Administrator shall review and determine all claims for benefits under the Plan. Notwithstanding the foregoing, the Plan Administrator may delegate its authority and responsibilities under the Plan to any officer of the Company; provided that no officer to whom any such authority or responsibilities is delegated may make any determination under the Plan which affects his or her eligibility for Separation Benefits or the amount thereof.

11.6 Claim Procedure.

(a) Filing a Claim. All claims and inquiries concerning benefits under the Plan must be submitted to the Plan Administrator in writing. The claimant may submit written comments, documents, records or any other information relating to the claim. Furthermore, the claimant shall be provided, upon request and free of charge, reasonable access to, and copies of, all documents, records and other information relevant to the claim for benefits. If an Employee or former Employee makes a written request alleging a right to receive benefits under the Plan or alleging a right to receive an adjustment in benefits being paid under the Plan, the Company shall treat it as a claim for benefits.

(b) Review of Claims; Claims Denial. The Plan Administrator shall initially deny or approve all claims for benefits under the Plan. If any claim for benefits is denied in whole or in part, the Plan Administrator shall notify the claimant in writing of such denial and shall advise the claimant of his right to a review thereof. Such written notice shall set forth, in a manner calculated to be understood by the claimant, specific reasons for such denial, specific references to the Plan provisions on which such denial is based, a description of any information or material necessary for the claimant to perfect his claim, an explanation of why such material is necessary and an explanation of the Plan's review procedure, and the time limits applicable to such procedures. Furthermore, the notification shall include a statement of the claimant's right to bring a civil action under Section 502(a) of ERISA following an adverse benefit determination on review. Such written notice shall be given to the claimant within a reasonable period of time, which normally shall not exceed 90 days, after the claim is received by the Plan Administrator.

(c) Appeals. Any claimant or his duly authorized representative, whose claim for benefits is denied in whole or in part, may appeal such denial by submitting to the Plan Administrator a request for a review of the claim within 60 days after receiving written notice of such denial from the Plan Administrator. The Plan Administrator shall give the claimant upon request, and free of charge, reasonable access to, and copies of, all documents, records and other information relevant to the claim of the claimant, in preparing his request for review. The request for review must be in writing. The request for review shall set forth all of the grounds upon which it is based, all facts in support thereof, and any other matters which the claimant deems pertinent. The Plan Administrator may require the claimant to submit such additional facts, documents, or other materials as the Plan Administrator may deem necessary or appropriate in making its review.

(d) Review of Appeals. The Plan Administrator shall act upon each request for review within 60 days after receipt thereof. The review on appeal shall consider all comments, documents, records and other information submitted by the claimant relating to the claim without regard to whether this information was submitted or considered in the initial benefit determination.

(e) Decision on Appeals. The Plan Administrator shall give written notice of its decision to the claimant. If the Plan Administrator confirms the denial of the application for benefits in whole or in part, such notice shall set forth, in a manner calculated to be understood by the claimant, the specific reasons for such denial, and specific references to the Plan provisions on which the decision is based. The notice shall also contain 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 for benefits. Information is relevant to a claim if it was relied upon in making the benefit determination or was submitted, considered or generated in the course of making the benefit determination, whether it was relied upon or not. The notice shall also contain a statement of the claimant's right to bring an action under ERISA Section 502(a). If the Plan Administrator has not rendered a decision on a request for review within 60 days after receipt of the request for review, the claimant's claim shall be deemed to have been approved. The Plan Administrator's decision shall be final and not subject to further review within the Company. There are no voluntary appeals procedures after appellate review by the Plan Administrator.

(f) Determination of Time Periods. If the day on which any of the foregoing time periods is to end is a Saturday, Sunday or holiday recognized by the Company, the period shall extend until the next following business day.

11.7 Attorneys' Fees. In the event of any legal proceeding brought by the Participant to enforce any of the Participant's rights under the Plan, the Company shall be responsible to pay or reimburse the Participant for all reasonable attorney's fees and costs incurred by the Participant in connection with such proceeding; provided, that the Participant prevails on at least one material claim in such proceeding. If fees and costs are required to be reimbursed under this provision, such reimbursement shall occur no later than March 15 of the calendar year next following the calendar year in which the obligation to reimburse such fees and costs was determined.

11.8 Unfunded Plan Status. All payments pursuant to the Plan shall be made from the general funds of the Company and no special or separate fund shall be established or other segregation of assets made to assure payment. No Participant or other person shall have under any circumstances any interest in any particular property or assets of the Company as a result of participating in the Plan. Notwithstanding the foregoing, the Company may (but shall not be obligated to) create one or more grantor trusts, the assets of which are subject to the claims of the Company's creditors, to assist it in accumulating funds to pay its obligations under the Plan.

11.9 Code Section 409A Savings Clause. The payments and benefits provided hereunder are intended to be exempt from or compliant with the requirements of Code Section 409A. Notwithstanding any provision of the Plan 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 Code Section 409A, the Company shall have the right to adopt such amendments to the 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 Code Section 409A or to comply with the requirements of Code Section 409A and thereby avoid the application of penalty taxes thereunder; provided, however, that this Section

11.10 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.

11.10 Validity and Severability. The invalidity or unenforceability of any provision of the Plan shall not affect the validity or enforceability of any other provision of the Plan, which shall remain in full force and effect, and any prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction.

11.11 Governing Law. The validity, interpretation, construction and performance of the Plan shall in all respects be governed by the laws of Colorado without reference to principles of conflict of law, except to the extent pre-empted by Federal law.

I hereby certify that this QEP Resources, Inc. Executive Severance Compensation Plan – CIC was duly adopted by the Board of Directors of QEP Resources, Inc. on February 23, 2014.

Executed on this 23rd day of February, 2014.

By: /s/ Charles B. Stanley

Charles B. Stanley
President and Chief Executive Officer

Exhibit 12.1

QEP Resources, Inc.
Ratio of Earnings to Fixed Charges

	Year Ended December 31,				
	2013	2012	2011	2010	2009
Earnings					
Income from continuing operations before income taxes and adjustment for income or loss from equity investees	**$ 291.2**	$ 198.5	$ 422.0	$ 458.3	$ 330.3
Add (deduct):					
Fixed charges	**167.8**	128.7	95.7	89.8	72.1
Distributed income from equity investees	**6.7**	7.9	7.9	2.4	1.1
Capitalized interest	**(2.0)**	(3.4)	(3.0)	(3.1)	—
Minority interest in pre-tax income of subsidiaries that have not incurred fixed charges	**6.2**	(3.1)	(3.2)	(2.9)	(2.6)
Total earnings	**$ 469.9**	$ 328.6	$ 519.4	$ 544.5	$ 400.9
Fixed Charges					
Interest expense	**$ 163.3**	$ 122.9	$ 90.0	$ 84.4	$ 70.1
Capitalized interest	**2.0**	3.4	3.0	3.1	—
Estimate of the interest within rental expense	**2.5**	2.4	2.7	2.3	2.0
Total Fixed Charges	**$ 167.8**	$ 128.7	$ 95.7	$ 89.8	$ 72.1
Ratio of Earnings to Fixed Charges	**2.8**	2.6	5.4	6.1	5.6

Exhibit 21.1

QEP Resources, Inc.
Subsidiaries of the Company

Name	State of Organization
QEP Energy Company [1]	Texas
QEP Field Services Company [1]	Delaware
QEP Marketing Company [1]	Utah
Uintah Basin Field Services, LLC [5]	Delaware
Rendezvous Gas Services, LLC [3]	Wyoming
Three Rivers Gathering, LLC [4]	Delaware
Rendezvous Pipeline Company, LLC [8]	Colorado
Perry Land Management Company, LLC [2]	Oklahoma
Roden Participants, LTD [7]	Texas
Clear Creek Storage Company, LLC [6]	Utah
Wyoming Peak Land Company, LLC [12]	Wyoming
QEP Midstream Partners GP, LLC [2]	Delaware
QEP Midstream Partners, LP [9]	Delaware
QEP Midstream Partners Operating, LLC [10]	Delaware
QEP Gathering I, LLC [11]	Delaware

(1) 100% owned by QEP Resources, Inc.
(2) 100% owned by QEP Field Services Company
(3) 78% owned by QEPM Gathering I, LLC
(4) 50% owned by QEP Midstream Partners Operating, LLC
(5) 38% owned by QEP Field Services Company
(6) 100% owned by QEP Marketing Company
(7) 14% owned by QEP Energy Company
(8) 100% owned by QEPM Gathering I, LLC
(9) 55.8% owned by QEP Field Services Company and 2% owned by QEP Midstream Partners GP, LLC
(10) 100% owned by QEP Midstream Partners, LP
(11) 100% owned by QEP Midstream Partners Operating, LLC
(12) 100% owned by QEP Energy 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 25, 2014, relating to the consolidated financial statements, financial statement schedule and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 25, 2014

Exhibit 23.2

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the following Registration Statements:

1. Registration Statement (Form S-8 No. 333-167726) pertaining to the QEP Resources, Inc. Long-Term Stock Incentive Plan,

2. Registration Statement (Form S-8 No. 333-167727) pertaining to the QEP Resources, Inc. Employee Investment Plan,

3. Registration Statement (Form S-3 No. 333-165805) of Questar Market Resources, Inc. (predecessor of QEP Resources, Inc.) and in the related Prospectus

of our report dated February 24, 2012, with respect to the consolidated financial statements and schedule of QEP Resources, Inc. for the one year period ended December 31, 2011 included in this Annual Report (Form 10-K) of QEP Resources, Inc. for the year ended December 31, 2013.

/s/ Ernst & Young LLP

Denver, Colorado
February 21, 2014

Exhibit 23.3

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, 2008, 2009, 2010, 2011, 2012 and 2013 incorporated herein by reference into Registration Statement Nos. 333-165805 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 25, 2014

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 2013 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 2013 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	2/25/2014
/s/ Phillip S. Baker Phillips S. Baker	Director	2/25/2014
/s/ Julie A. Dill Julie A. Dill	Director	2/25/2014
/s/ L. Richard Flury L. Richard Flury	Director	2/25/2014
/s/ Robert F. Heinemann Robert F. Heinemann	Director	2/25/2014
/s/ Robert E. McKee Robert E. McKee	Director	2/25/2014
/s/ Thomas C. O'Connor Thomas C. O'Connor	Director	2/25/2014
/s/ M. W. Scoggins M. W. Scoggins	Director	2/25/2014
/s/ David A. Trice David A. Trice	Director	2/25/2014
/s/ William L. Thacker III William L. Thacker III	Director	2/25/2014

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, 2013;

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 25, 2014

/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, 2013;

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 25, 2014

/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, 2013, 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 25, 2014

/s/ Charles B. Stanley

Charles B. Stanley
Chairman, President and Chief Executive Officer

February 25, 2014

/s/ Richard J. Doleshek

Richard J. Doleshek
Executive Vice President,
Chief Financial Officer, Treasurer and
Chief Accounting Officer

Exhibit 99.1

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

January 15, 2014

QEP Energy Company
1050 Seventeenth Street, Suite 500
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, 2013. 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 15, 2014 and presented herein, was prepared for public disclosure by QEP in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of QEP as of December 31, 2013.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2013, 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 ending date of the period covered in 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, 2013

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Remaining Reserves				
Oil/Condensate – Barrels	71,010,633	820,628	76,750,520	148,581,781
Plant Products – Barrels	49,260,039	3,529,815	49,803,365	102,593,219
Gas – MMCF	1,312,013	94,289	1,148,534	2,554,836
Income Data M$				
Future Gross Revenue	$ 11,191,510	$ 452,855	$ 11,315,976	$ 22,960,341
Deductions	3,821,058	232,105	6,558,468	10,611,631
Future Net Income (FNI)	$ 7,370,452	$ 220,750	$ 4,757,508	$ 12,348,710
Discounted FNI @ 10%	$ 4,218,338	$ 107,169	$ 1,647,022	$ 5,972,529

Liquid hydrocarbons are expressed in standard 42 gallon barrels. 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™ 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 variable operating costs primarily resulting from salt water disposal charges. 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 effects nor any impairment conditions. Liquid hydrocarbon reserves account for approximately 64 percent and gas reserves account for the remaining 36 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. The results for all five discount factors are shown in summary form as follows.

	Discounted Future Net Income M$ As of December 31, 2013
Discount Rate Percent	Total Proved
5	$8,197,308
9	$6,327,509
10	$5,972,529
15	$4,620,310
20	$,3,724,511

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "Petroleum Reserves Definitions" is included as an attachment to this report.

The various proved reserve status categories are defined under the attachment entitled "Petroleum Reserves Status Definitions and Guidelines" in this report. The proved developed non producing reserves included herein consist of the shut-in and behind pipe categories.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All 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- 1O(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 2013 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 non producing 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 2013. 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 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

QEP has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by QEP with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, 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 ending date of the period covered in 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, 2013. 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	$96.94/Bbl	$85.13/Bbl
	NGLs	WTI Cushing	$96.94/Bbl	$30.88/Bbl
	Gas	Henry Hub	$3.67/MMBTU	$3.52/MCF

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations

Costs

The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by QEP. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by QEP and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. The estimated net cost of abandonment after salvage was included for properties 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, 2013. 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, political or economic obstacles that would significantly alter their plans.

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 for over seventy-five years. 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 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, 2013 annual report on Form 10-K of QEP. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by QEP.

We have provided QEP with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by QEP and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580
\s\ Richard J. Marshall
Richard J. Marshall, P.E.
Colorado License No. 23260
Vice President
[Seal]

Approved:
\s\ James L. Baird
James L. Baird, P.E.
Colorado License No. 41521
Managing Senior Vice President

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.