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 Year Ended December 31, 2011

QEP Resources, Inc.

QEP RESOURCES, INC.

(Exact name of registrant as specified in its charter)

STATE OF DELAWARE	001-34778	87-0287750
(State or other jurisdiction of incorporation)	(Commission File No.)	(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 x 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 x

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 x 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 x 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. x

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	x		Accelerated filer	☐
Non-accelerated filer	o	(Do not check if a smaller reporting company)	Smaller reporting company	☐

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

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, 2011): $7,399,937,572.

At January 31, 2012, there were 177,498,486 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 2011 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). Prior to QEP's Spin-off from Questar Corporation (described in more detail in the Explanatory Note in Item 1 of Part I of this Annual Report on Form 10-K), QEP's predecessor, Questar Market Resources, Inc., filed annual, quarterly and current reports with the SEC. QEP also regularly files proxy statements and other documents with the 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 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;
- plans to drill or participate in wells;
- future expenses and operating costs;
- belief that QEP has one of the lowest cash cost structures among its peers;
- the outcome of contingencies such as legal proceedings;
- expected contributions to the Company's retirement plans;
- results from planned drilling operations and production operations;
- amount and allocation of forecasted capital expenditures and plans for funding capital expenditures;
- impact of recently issued accounting pronouncements;
- the amount and timing of the settlement of derivative contracts;
- the significance of Adjusted EBITDA as a measure of cash flow and liquidity;
- the ability of QEP to use derivative instruments to manage commodity price risk;
- the ability to secure long-term gathering, processing and treating contracts from third parties as required to fully utilize the Company's midstream assets;
- operation of the Company's Blacks Fork II and other processing plants at assumed capacities;
- QEP's ability to develop reserves and grow production as necessary to satisfy delivery commitments and our ability to purchase natural gas, crude oil and NGL's in the market to cover any shortfalls;
- payment of dividends;
- plans to hedge a portion of forecasted production;
- conversion of proved undeveloped reserves to proved developed reserves;
- acquisition strategy; and
- growth strategy.

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;
- 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;
- operating risks such as unexpected drilling conditions;
- weather conditions;
- changes in maintenance and construction costs, including possible inflationary pressures;
- changes in industry trends;
- the availability and cost of debt financing;
- changes in laws or regulations, including the implementation of the Dodd-Frank Act;
- actions, or inaction, by federal, state, local or tribal governments; 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, in other documents, or on the website to reflect future events or circumstances. All such statements are expressly qualified by this cautionary statement.

Glossary of Commonly Used Terms

B Billion.

bbl Barrel, which is equal to 42 U.S. gallons 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.

cash flow hedge A derivative instrument that complies with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 815 and is used to reduce the exposure to variability in cash flows from the forecasted physical sale of gas and oil production whereby the gains (losses) on the derivative transaction are anticipated to offset the losses (gains) on the forecasted physical sale.

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.

cushion gas Volume of gas that must remain in a storage facility to provide the required pressure to extract the stored or working gas volumes.

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 into a known producing formation in a previously discovered field.

dry hole A well drilled or junked 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 into a previously untested geologic prospect to determine the presence of gas or oil.

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.

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

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

hedging The use of commodity and interest-rate derivative instruments to reduce financial exposure to commodity price and interest-rate volatility.

IFNPCR Inside FERC monthly settlement index for the Northwest Pipeline Corp. Rocky Mountains.

IFPEPL Inside FERC monthly settlement index for the Panhandle Eastern Pipeline Company.

M Thousand.

MM Million.

Midstream Gas gathering, compression, treating, processing, and transmission assets and activities that are non-jurisdictional. Also includes certain 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" gas and oil wells or "net" acres are determined by the sum of the fractional ownership working 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.

proved reserves Those quantities of natural gas, oil, condensate and NGL which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from known reservoirs 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, 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 natural gas and/or oil that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

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

T Trillion.

undeveloped reserves Reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. See 17 C.F.R. Section 4-10(a)(31).

working interest An interest in a gas and oil 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.

FORM 10-K
ANNUAL REPORT 2011

PART I

ITEM 1. BUSINESS

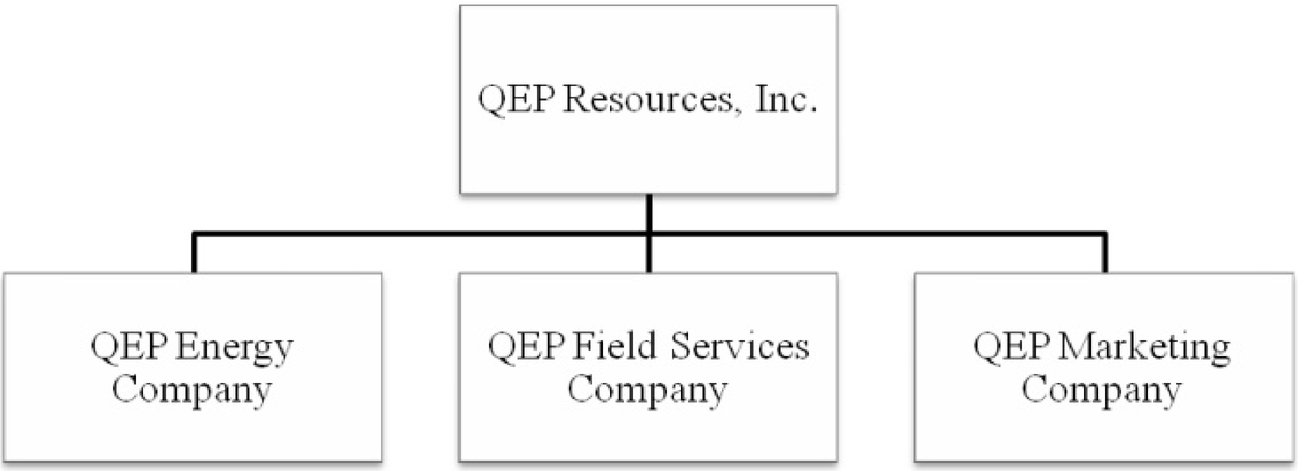
Nature of Business

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

- QEP Energy Company (QEP Energy) acquires, explores for, develops and produces natural gas, oil, and natural gas liquids (NGL);
- QEP Field Services Company (QEP Field Services) provides midstream field services, including natural gas gathering, processing, compression and treating services for affiliates and third parties; and
- QEP Marketing Company (QEP Marketing) markets affiliate and third-party natural gas and oil, provides risk-management services, and owns and operates an underground gas-storage reservoir.

QEP operates in the Northern (formerly referred to as the Rocky Mountain Region) and Southern (formerly referred to as the Midcontinent Region) Regions of the United States and is headquartered in Denver, Colorado. Principal offices are located in Denver, Colorado; Salt Lake City, Utah; Oklahoma City, Oklahoma; and Tulsa, Oklahoma.

The corporate-organization structure and principal subsidiaries are depicted below:



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 Form 10-K presents QEP's financial results as an independent company separate from Questar and reflects Wexpro's financial condition and operating results as discontinued operations for all periods presented. A summary of discontinued operations can be found in Note 2 to the consolidated financial statements in Item 8 of this Annual Report on Form 10-K.

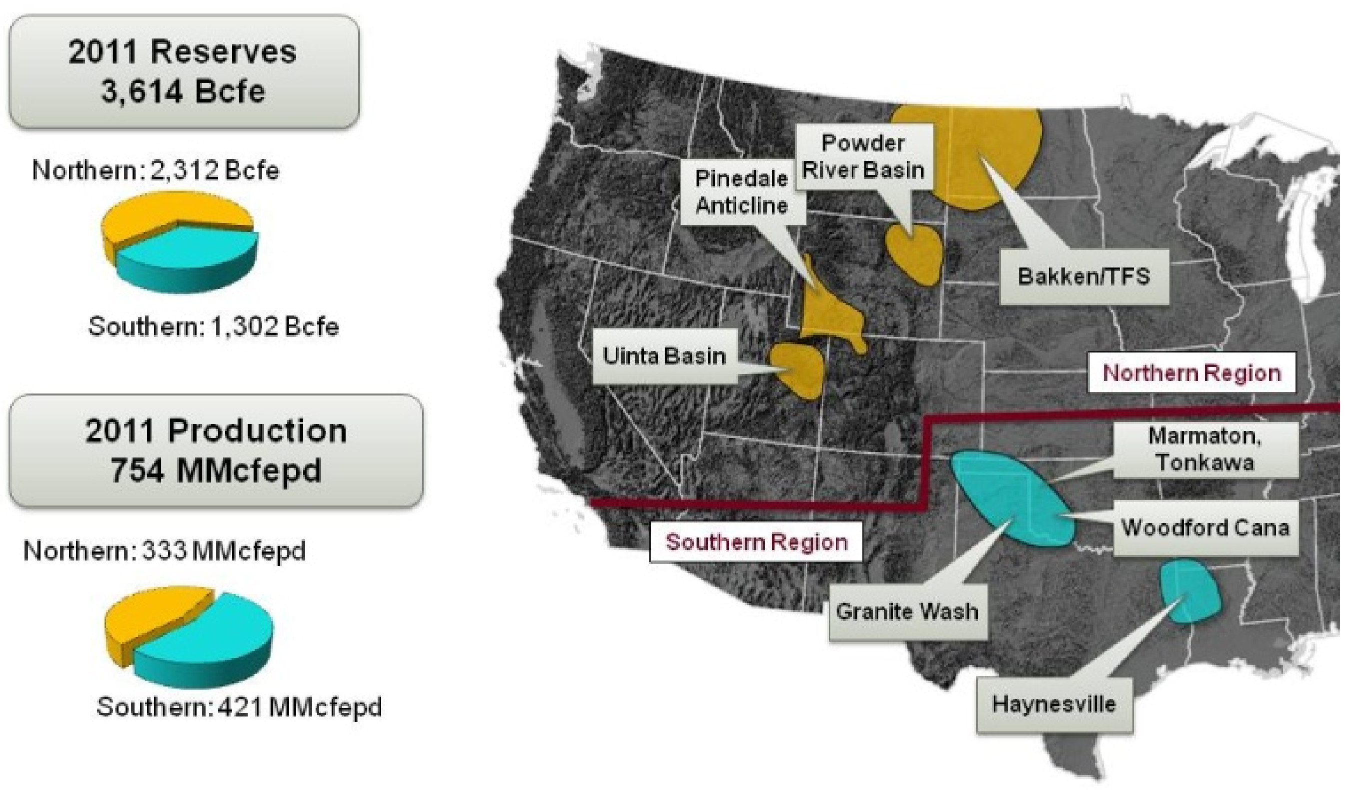
Strategies

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

- Operate in a safe and environmentally responsible manner
- Allocate capital to the projects that generate the best returns
- Maintain a sustainable inventory of low-cost, high margin resource plays
- Be in the best parts of the plays in which we operate
- Build contiguous acreage positions to drive efficiencies
- Be the operator of our assets whenever possible
- Be the low-cost driller and producer in each area where we operate
- Own and operate midstream infrastructure in our core producing areas to control our future and capture value downstream of the wellhead
- Build gas processing plants to extract liquids from our gas streams
- Gather, compress and treat our production to drive down costs
- Actively market our QEP Energy production to maximize value
- Utilize commodities derivatives to reduce the impact of a decline in the prices of our natural gas, crude oil or NGL and to lock in acceptable cash flows to support future capital expenditures
- Attract and retain the best people
- Maintain a strong balance sheet and financial flexibility that allows us to take advantage of both organic growth and acquisition opportunities

EXPLORATION AND PRODUCTION – QEP Energy Company

General: QEP Energy is actively involved in several of North America's most important hydrocarbon resource plays. For 2012, QEP plans to allocate approximately 88% of its capital budget to QEP Energy. The following map illustrates the location of the Company's significant exploration and production activities, our Northern and Southern Regions described elsewhere in this report, and related reserve and production data:



QEP's exploration and production activities are conducted through QEP Energy, which generated approximately 76%, 81%, and 85% of the Company's Adjusted EBITDA during the years ended December 31, 2011, 2010 and 2009, respectively. QEP Energy operates in two core regions – the Northern Region (including the states of Wyoming, Utah, Colorado, New Mexico and North Dakota) and the Southern Region (including the states of Oklahoma, Texas and Louisiana). The Southern Region contributed approximately 56% of 2011 production while the Northern Region contributed the remaining 44%. QEP Energy reported 3,614 Bcfe of estimated proved reserves as of December 31, 2011, up from 3,031 Bcfe at the end of 2010. Of those estimated proved reserves, approximately 64%, or 2,312 Bcfe, were located in the Northern Region at December 31, 2011, compared to 61% or 1,860 Bcfe at December 31, 2010. The remaining 36%, or 1,302 Bcfe at December 31, 2011, were located in the Southern Region, compared to 39% or 1,171 Bcfe at December 31, 2010. Approximately 54% of the proved reserves reported by QEP Energy at year end 2011 were developed, while 46% were categorized as proved undeveloped. Approximately 24% of the total proved reserves at December 31, 2011 were comprised of crude oil and NGL up from 14% at December 31, 2010.

QEP Energy has a large inventory of identified development drilling locations, primarily on the Pinedale Anticline in western Wyoming; the Haynesville/Cotton Valley area in northwestern Louisiana; the Midcontinent area with properties primarily in Oklahoma and Texas; the Uinta Basin in eastern Utah; and the Rockies Legacy, which includes the Bakken/Three Forks area in western North Dakota and other properties in Wyoming. QEP Energy continues to conduct exploratory drilling to determine the commerciality of its inventory of unproven leaseholds. The Company seeks to acquire, develop and produce natural gas and oil from so-called “resource plays” in its core areas. Resource plays are characterized by continuous, aerially extensive hydrocarbon accumulations in tight sand, shale and coal reservoirs. 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. QEP Energy seeks to maintain geographical and geological diversity with its two core regions. The Company has in the past and may in the future pursue acquisition of producing properties through the purchase of assets or corporate entities to expand its presence in its core areas or to create new core areas.

Competition and Customers: QEP Energy faces competition in every part of its business, including the acquisition of producing leasehold and wells and undeveloped leasehold, the marketing of natural gas and oil, and obtaining 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 them in a low-cost and efficient manner.

QEP Energy, both directly and through QEP Marketing, sells natural gas production to a variety of customers, including gas-marketing firms, industrial users and local-distribution companies. QEP Energy regularly evaluates counterparty credit and may require financial guarantees or prepayments from parties that fail to meet its credit criteria.

Regulation: QEP Energy operations are subject to extensive government controls and regulation at the federal, state and local levels. QEP Energy must obtain permits to drill and produce wells; maintain required bonds to drill and operate wells; submit and implement spill-prevention plans; and file notices relating to the presence, use, and release of specified contaminants in air and water emissions and discharges incidental to gas and oil drilling, completion and production. QEP Energy is also subject to various conservation matters, including regulation of the size of drilling and spacing units, the number of wells that may be drilled in a unit and the unitization or pooling of gas and oil properties. Currently, all well construction activities, including hydraulic fracture stimulation, are regulated by state agencies that review and approve all aspects of natural gas and oil well design and operation. Most of QEP Energy’s leasehold acreage in the Northern Region is held under leases granted by the United States and administered by federal agencies, principally the Bureau of Land Management (BLM). Current federal regulations restrict activities during certain times of the year on significant portions of QEP Energy leasehold due to wildlife activity and/or habitat. QEP Energy has worked with federal and state officials in Wyoming to obtain authorization for limited winter-drilling activities on the Pinedale Anticline and has developed measures, such as drilling multiple wells from a single pad location, to minimize the impact of its activities on wildlife and wildlife habitat. Various wildlife species inhabit QEP Energy leaseholds at Pinedale and in other areas. The presence of wildlife or plants, including species and types that are protected under the Federal Endangered Species Act, could limit access to leases held by QEP Energy on public lands.

In September 2008, the BLM issued a Record of Decision (ROD) on the Final Supplemental Environmental Impact Statement (FSEIS) for long-term development of natural 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.

See also “Risk Factors – Risk Related to Regulation.”

MIDSTREAM FIELD SERVICES – QEP Field Services Company

General: QEP invests in midstream (gathering, processing and treating) systems to complement its natural gas, oil and NGL operations in regions where QEP Energy has production. Through ownership and operation of these facilities, QEP is able to better manage the timing and costs associated with bringing on new production and enhance the value received for gathering, processing and treating the Company’s production. In addition, QEP’s midstream business also provides midstream services to third-party customers, including major and independent producers. QEP generates revenues from its midstream activities through a variety of agreements including fixed-fee, percent-of-proceeds and keep-whole agreements. For 2012, QEP plans to allocate approximately 12% if its capital budget to QEP Field Services.

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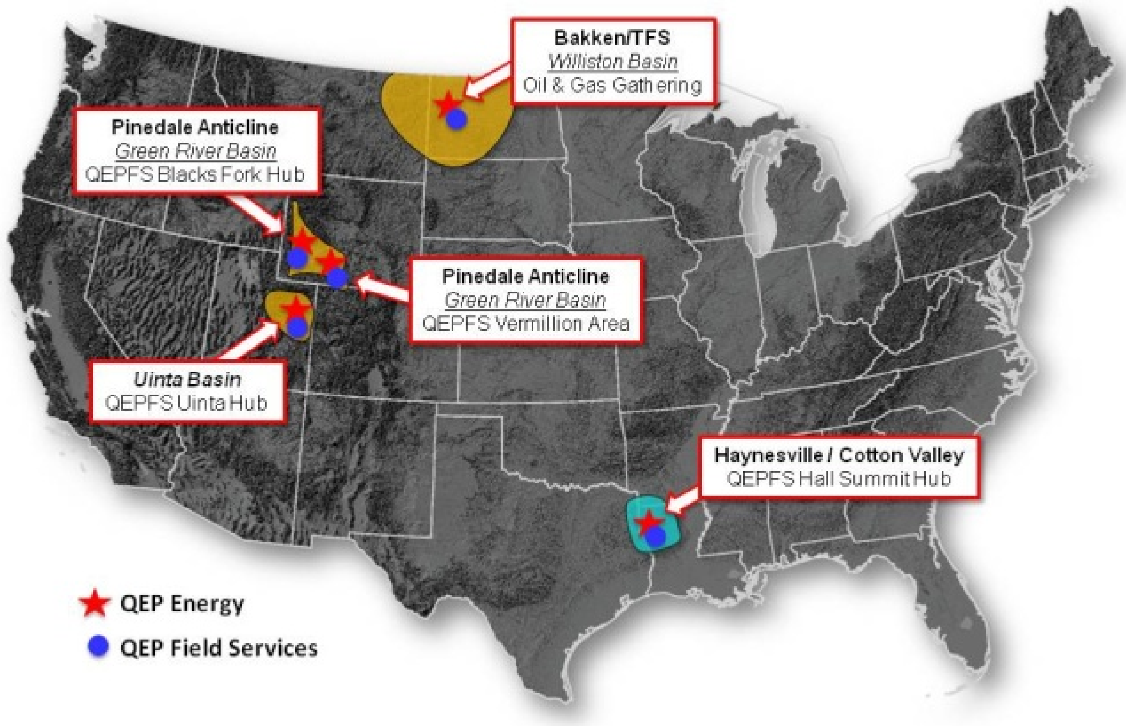
The following map illustrates QEP Field Services areas of operations and the locations corresponding with QEP Energy's operating areas:



QEP Field Services generated approximately 23%, 18% and 14% of the Company's Adjusted EBITDA in the years ended December 31, 2011, 2010 and 2009, respectively. QEP Field Services owns various natural gas gathering, treating and processing facilities in the Northern and Southern Regions as well as 78% of Rendezvous Gas Services, LLC, (RGS), a partnership that operates gas gathering facilities in western Wyoming. The FERC-regulated Rendezvous Pipeline Co., LLC (Rendezvous Pipeline), a wholly owned subsidiary of QEP Field Services, operates a 21-mile, 20-inch-diameter pipeline between QEP Field Services' Blacks Fork gas-processing plant and the Muddy Creek compressor station owned by Kern River Gas Transmission Co. (Kern River Pipeline). RGS gathers natural gas for Pinedale Anticline and Jonah Field producers for delivery to various interstate pipelines. QEP Field Services also owns 38% of Uintah Basin Field Services, LLC (UBFS) and 50% of Three Rivers Gathering, LLC (Three Rivers). These two partnerships operate natural gas gathering facilities in eastern Utah.

Fee-based gathering and processing revenues were 70%, 78% and 82% of QEP Field Services' net operating revenues (revenues less plant shrink and transportation costs) during the years ended December 31, 2011, 2010 and 2009, respectively. Approximately 35%, 36%, and 43% of QEP Field Services' 2011, 2010 and 2009 net gas processing revenues (processing revenues less plant shrink and transportation costs) 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 commodity price exposure. To further reduce volatility associated with keep-whole contracts, QEP Field Services may enter into forward-sales contracts for NGL or hedge NGL prices and equivalent gas volumes with the intent to lock in a processing margin.

Competition and Customers: QEP Field Services faces regional competition with varying competitive factors in each basin. QEP Field Service's gathering and processing business competes with other midstream companies, interstate and intrastate pipelines, producers and independent gatherers and processors. Numerous factors impact a customer's choice of a gathering or processing services provider, including rate, location, 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 and in northwest Louisiana. Most of QEP Field Services' gas gathering, processing and treating services are provided under long-term agreements.

Regulation: QEP Field Services' construction and operation activities are subject to various local, state and federal rules and regulations. Most of these rules and regulations are administered by the federal Department of Transportation (DOT), the Occupational Safety and Health Administration (OSHA), and the Environmental Protection Agency (EPA). Many of QEP's systems in the Northern Region are constructed and operated on public lands owned by the United States and administered by the Bureau of Land Management (BLM). Construction and operation of facilities on non-public land may also be subject to various regulations administered by state, tribal or local authorities.

Section 1(b) of the Natural Gas Act exempts gathering activities from regulation or jurisdiction by the Federal Energy Regulatory Commission (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 our 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 therefore cannot guarantee that the jurisdictional status of its gathering systems will remain unchanged. Several of QEP's facilities have been determined to be under 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, and public daily capacity and flow reporting requirements. QEP's gas gathering systems are not subject to state utility regulations.

Additional rules and regulations pertaining to QEP Field Services activities are adopted from time to time. QEP cannot predict what impact, if any, such rules and regulations might have on its operations, but QEP may be forced to incur additional capital expenditures and/or increased operating costs as a result of such changes.

See also “Risk Factors – Risk Related to Regulation.”

ENERGY MARKETING—QEP Marketing Company

General: QEP Marketing provides wholesale marketing and sales of affiliate and third-party natural gas, oil and NGL and generated approximately 1%, of the Company’s Adjusted EBITDA in the years ended December 31, 2011, 2010 and 2009, respectively. As a wholesale marketing entity, QEP Marketing concentrates on markets in the Rocky Mountains, Pacific Northwest 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 baseload-storage facility.

QEP Marketing, through its subsidiary Clear Creek Storage Company, LLC, 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.

Competition and Customers: 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 natural gas and volumes purchased from third parties to wholesale marketers, industrial end-users and utilities. QEP Marketing sells QEP Energy crude oil volume to refiners, remarketers and other companies, including some with pipeline facilities near company producing properties. QEP Marketing sells NGL volumes from its Clear Creek storage facility to a refiner. In the event pipeline facilities are not available, QEP Marketing arranges transportation of crude oil by truck or rail to storage, refining or pipeline facilities. QEP Marketing uses derivative instruments to manage commodity price risk, on behalf of QEP Energy and QEP Field Services, using fixed-price swaps or collars to secure a known price or price floor for a specific volume of production. QEP Marketing does not engage in speculative hedging transactions. See Item 7A and Notes 1 and 7 to the consolidated financial statements included in Item 8 of Part II of this Annual Report for additional information relating to hedging activities.

Regulation: The U.S. Commodities Future Trading Commission, which has regulatory authority over swap transactions under the Dodd-Frank Act, has adopted various rules which impose compliance requirements upon QEP Marketing’s derivatives trading practices. *See* also “Risk Factors – Risks Related to Regulation.”

FERC has jurisdiction over the operation of QEP Marketing’s Clear Creek storage facility, through the Clear Creek Storage Company LLC subsidiary in which QEP Marketing is the sole member, by virtue of the facility being connected 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 charges for transmission, open access/non-discrimination, and public disclosure via an electronic bulletin board of daily capacity and flows.

Employees

At December 31, 2011, QEP Resources, Inc. had 876 employees compared to 823 employees at December 31, 2010. None of QEP’s employees are represented by unions or covered by collective bargaining agreements.

Executive Officers of the Registrant

The name, age, period of service, title and business experience of each of QEP’s executive officers as of February 24, 2012, are listed below:

Charles B. Stanley	53	President, Chief Executive Officer, QEP (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	53	Executive Vice President and Chief Financial Officer, QEP (2010 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).
Jay B. Neese	53	Executive Vice President, QEP (2010 to present). Previous titles with Questar: Senior Vice President (2005 to 2010); Executive Vice President, Market Resources and Market Resources subsidiaries (2005 to 2010); Vice President, Market Resources and Market Resources subsidiaries (2003 to 2005); Assistant Vice President (2001 to 2003).
Perry H. Richards	51	Senior Vice President – Field Services (2010 to present). Previous title with Questar: Vice President, Questar Gas Management (2005 to 2010).
Eric L. Dady	57	Vice President and General Counsel, QEP (2010 to present). Previous title with Questar: General Counsel Market Resources (2005 to 2010).
Abigail L. Jones	51	Vice President, Compliance, Corporate Secretary and Assistant General Counsel, QEP (2010 to present). Previous titles with Questar: Vice President Compliance (2007 to 2010); Corporate Secretary (2005 to 2010); Assistant Secretary (2004 to 2005).

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 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.

Risks Inherent in the Company's Business

The prices for natural gas, oil and NGL are volatile, and a decline in such prices could adversely affect QEP's results, stock price and growth plans. Historically natural 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. 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 natural gas, the Company's financial results are substantially more sensitive to changes in natural gas prices than to changes in oil prices.

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

- changes in domestic and foreign supply of natural gas, oil and NGL;
- changes in local, regional, national and global demand for natural 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 natural gas, oil and NGL;
- the potential long-term impact of an abundance of natural gas from unconventional sources on the global gas supply;
- domestic political developments and actions;
- weather conditions;
- domestic government regulations and taxes, including regulations or legislation relating to climate change or natural gas and oil 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 natural gas, oil, and NGL; and
- the quality of natural gas and oil produced.

In addition, lower commodity prices may result in asset impairment charges from reductions in the carrying values of QEP's natural gas and oil properties or a reduction in the carrying value of goodwill. During the fourth quarter of 2011, QEP recorded a non-cash price-related impairment charge of $195.2 million on some of QEP Energy's mature, dry gas, and higher cost properties in both the Northern and Southern Regions. The impairment charge related to the reduced value of these areas resulting from lower natural gas prices and the current forward curve for natural gas prices. See Item 8, footnote 1, "Summary of Significant Accounting Policies" for additional information.

Slower economic growth rates in the US may materially adversely impact QEP's operating results. The US 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 are likely to be significant long-term effects resulting from the financial crisis and recession, including a future global economic growth rate that is slower than what was experienced in the years leading up to the crisis, and more volatility may occur before a sustainable, yet lower, growth rate is achieved. In addition, the Organization for Economic Cooperation and Development (OECD) has encouraged countries with large federal budget deficits, such as the US, to initiate deficit reduction measures. Such measures, if they are undertaken too rapidly, could further undermine economic recovery and slow growth by reducing demand. 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 natural gas, oil and NGL production. A decrease in demand, excluding changes in other factors, could potentially result in lower commodity prices, which would reduce QEP's cash flows from operations and its profitability.

The Company may not be able to economically find and develop new reserves. The Company's profitability depends not only on prevailing prices for natural gas, oil and NGL, but also its ability to find, develop and acquire gas and oil reserves that are economically recoverable. Producing natural gas and oil reservoirs are generally characterized by declining production rates that vary depending on reservoir characteristics. Because natural gas and oil production volumes from QEP wells typically decline by 60% or more 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 gas and oil reserves to replace those depleted by production.

Gas and oil reserve estimates are imprecise and subject to revision. QEP's proved natural gas and oil reserve estimates are prepared annually by independent reservoir-engineering consultants. Gas and oil 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 the current market value of the estimated natural gas and oil 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 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 oilfield equipment, services and qualified personnel could impact results of operations. The demand for and availability of qualified and experienced field personnel to drill wells and conduct field operations, including geologists, geophysicists, engineers and other professionals in the oil and gas industry can fluctuate significantly, often in correlation with natural gas and oil 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 natural gas and oil prices.

QEP's operations involve numerous risks that might result in accidents and other operating risks and costs. Drilling of natural gas and oil wells is potentially a high-risk activity. Risks include:

- fire, explosions and blow-outs;
- unexpected drilling conditions such as abnormally pressured formations;
- pipe, cement or casing failures;
- plant, pipeline, and other facility accidents and failures; and
- environmental accidents such as oil spills, natural gas leaks, ruptures or discharges of toxic gases, brine water or well fluids (including groundwater contamination).

The Company 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 investigation; 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, the Company may also be exposed to the risks enumerated above that are not within its care, custody or control.

There are also inherent operating risks and hazards in the Company's gas and oil production and gas gathering, processing and treating operations that could cause substantial financial losses. In addition, these risks could result in personal injury or loss of human life, significant damage to property, environmental pollution, impairment of operations and substantial losses. 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 the Company's pipelines run through such areas. In spite of the Company's precautions, an accident or other event could cause considerable harm to people or property, and could have a material adverse effect on the 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 activity. Such circumstances could adversely impact the Company's ability to meet contractual obligations.

As is customary in the gas and oil industry, the Company 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 exceed coverage limits. Losses and liabilities arising from uninsured or underinsured events could have a material adverse effect on QEP’s financial condition, results of operations and cash flows.

Lack of availability of pipeline capacity could impact results of operations. The lack of availability of satisfactory oil, natural gas and NGL transportation arrangements may hinder QEP’s access to oil, NGL and natural 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 pipelines 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, or other reasons. If pipelines do not exist near producing wells, if pipeline capacity is limited or if pipeline capacity is unexpectedly disrupted, sales could be reduced or production shut in, reducing profitability. 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. If pipeline quality requirements change, QEP might be required to install additional treating or processing equipment, which could also increase costs. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could also adversely affect QEP’s ability to transport natural gas and oil.

The fees charged to third parties under our 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 natural gas, oil or NGLs are curtailed or cut off. Force majeure events include (but are not limited to): revolutions, 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 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 natural gas and oil 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 deteriorated, making terms for certain financings less attractive, and in certain cases, resulting in the unavailability of certain types of financing. If QEP’s revenues decline as a result of lower natural gas, oil and 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 fix the interest rate on a portion of its floating-rate debt. The interest rates on debt under the Company’s revolving credit facility are tied to QEP’s ratio of indebtedness to Consolidated EBITDAX (as defined in the credit agreement.)

QEP relies on access to capital markets to meet long-term funding needs. A downgrade of credit ratings may make it more difficult or expensive to raise capital from financial institutions or other sources. QEP’s failure to obtain additional financing could result in a curtailment of its operations relating to exploration and development of its prospects, which in turn could lead to a possible reduction in QEP’s natural gas or oil production, reserves and its revenues, and could negatively impact its results of operations.

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 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 activism against oil and gas exploration and development activities. Opposition toward oil and gas drilling and development activity has been growing globally and is particularly pronounced in the United States. Companies in the oil and gas industry, such as QEP, are often the target of activist efforts from both individuals and non-governmental organizations regarding safety, environmental compliance and business practices. Anti-development activists are working to, amongst 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 have recently advocated for increased regulations on shale drilling in the U.S. Future activist efforts could result in the following:

- delay or denial of drilling permits;
- shortening of lease terms or reduction in lease size;
- restrictions on installation or operation of gathering or processing facilities;
- restrictions on the use of certain operating practices, such as hydraulic fracturing;
- increased severance and/or other taxes;
- legal challenges or lawsuits;
- damaging publicity about QEP;
- increased costs of doing business;
- reduction in demand for QEP’s products; and
- other adverse affects on QEP’s ability to develop its properties and expand production.

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

Risks Related to Strategy

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 natural gas, oil, and NGL prices and to protect cash flow, returns on capital, net income and credit ratings 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. Additionally, there are proposed financial regulations which 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 that have not been designated as cash flow hedges must be recorded into QEP’s income. This creates the risk of volatility in earnings even if no economic impact to QEP has occurred during the applicable period.

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

Relative changes in NGL product and natural gas prices may adversely impact QEP’s results due to frac spread, natural gas and liquids exposure. Approximately 30% and 22% of QEP Field Services’ net operating revenues for 2011 and 2010, respectively, were derived from keep-whole processing agreements. Under QEP’s keep-whole arrangements, QEP’s principal cost is delivering dry gas of an equivalent Btu content to replace Btus extracted from the gas stream in the form of NGLs, or consumed as fuel during processing. The spread between the NGL product sales price and the purchase price of natural gas with an equivalent Btu content is called the "frac spread." Generally, the frac spread and, consequently, the net operating margins are positive under these contracts. In the event natural gas becomes more expensive on a Btu equivalent basis than NGL products, QEP’s cost of keeping the producer "whole" results 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 price of ethane and ethane margins, which historically have been more volatile than the price of propane and butane. QEP competitors have also made significant investments in gas processing plants that recover significant volumes of ethane. The U.S. ethane market may, and probably will, become oversupplied from time to time in the future, resulting in lower ethane prices.

QEP's plans to grow its midstream business by constructing new processing and treating facilities subjects the Company to construction risks and the risk that the Company will not be able to secure long-term contracts from third parties required to earn acceptable returns on these investments. One of the ways QEP has grown its business is through the construction of new gathering, treating and processing facilities. The construction of gathering, treating and processing facilities requires the expenditure of significant amounts of capital and involves numerous regulatory, environmental, political, legal and inflationary uncertainties. If QEP undertakes these projects, QEP may not be able to complete them on schedule, or at all, or at the budgeted cost. While QEP may commit natural gas supplies from its production, such supplies many not be sufficient to fill available capacity at these facilities, leaving QEP with limited natural gas supplies committed to these facilities prior to and after their construction. Moreover, QEP may construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize. QEP may also rely on estimates of proved reserves in its decision to construct new facilities, which may prove to be inaccurate, because there are numerous uncertainties inherent in estimating quantities of proved reserves. As a result, new facilities may not be able to process or treat enough natural gas to achieve QEP's expected investment return, which could adversely affect QEP's operations and cash flows.

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 natural gas and oil exploration, exploitation, acquisition and production. QEP faces competition from:

- large multi-national, integrated oil companies;
- US independent oil and gas companies;
- service companies engaging in oil and gas exploration and production activities; and
- private oil and gas equity funds.

QEP faces competition in a number of areas such as:

- acquiring desirable producing properties or new leases for future exploration;
- marketing its natural gas, oil and NGL production;
- obtaining the equipment and expertise necessary to operate and develop properties; and
- attracting and retaining employees with certain 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 seismic and lease rights on natural gas and oil 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. This highly competitive environment could have an adverse impact on QEP's business.

QEP may be subject to risks in connection with acquisitions and organizational changes. The acquisition of gas and oil properties requires the assessment of recoverable reserves, future gas and oil sales prices and basis differentials, operating costs,and potential environmental and other liabilities. The accuracy of these assessments is inherently uncertain. QEP may not be able to identify attractive acquisition opportunities. Even if QEP does identify attractive opportunities, it may not be able to complete the acquisitions due to capital constraints. If QEP acquires an additional business, QEP could have difficulty integrating the operations, systems, management and other personnel and technology of the acquired business with QEP's own, or could assume unidentified or unforeseeable liabilities, resulting in a loss of value.

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.

Failure of the Company's controls and procedures to detect error 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 error 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 met. In addition, the design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be 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.

Risks Related to Regulation

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 regulation. The failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the Company's operations increases its cost of doing business and, consequently, affects its profitability. 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 its operations.

The Company is subject to extensive federal, state, tribal and local tax, environmental, health and safety laws and regulations. Environmental laws and regulations are complex, change frequently and tend to become more onerous over time. 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 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 threaten QEP's authorization to operate.

QEP must comply with numerous and complex federal and state regulations governing activities on federal, state and tribal lands, notably the National Environmental Policy Act, the Endangered Species Act, the Clean Air Act, the Clean Water Act, the Safe Drinking Water Act, the Oil Pollution Act, and the National Historic Preservation Act and similar state laws. Federal and state regulatory agencies frequently impose conditions on the Company's activities. These restrictions have become more stringent over time and can limit or prevent exploration and production on the Company's leasehold. Certain environmental groups oppose drilling on some of QEP's federal and state leases. These groups sometimes sue federal and state regulatory agencies for alleged procedural violations in an attempt to stop, limit or delay natural gas and oil development on public lands.

The United States Fish and Wildlife Service may designate critical habitat areas for certain listed threatened or endangered species. A critical habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or development. The listing of certain species, such as the sage grouse, as threatened and endangered, could have a material impact on the Company's operations in areas where such species are found.

The Clean Water Act and similar state laws regulate discharges of stormwater, wastewater, oil, and other pollutants to surface water bodies, such as lakes, rivers, wetlands, and streams. Failure to obtain permits for such discharges could result in civil and criminal penalties, orders to cease such discharges, and other costs and damages. 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.

Various federal agencies within the U.S. Department of the Interior, particularly the Bureau of Land Management and the Bureau of Indian Affairs, along with potentially each Native American tribe, promulgate and enforce regulations pertaining to natural gas and oil operations on Native American tribal lands. These regulations include such matters as lease provisions, drilling and production requirements, environmental standards and royalty considerations. In addition, under prevailing legal precedent each Native American tribe has limited attributes of sovereignty including the right to enforce laws and regulations independent from federal, state and local statutes and regulations so long as not inconsistent with federal law and regulation. These tribal laws and regulations include various taxes, fees, requirements to employ Native American tribal members and other conditions that apply to lessees, operators and contractors conducting operations on Native American tribal lands. Lessees and operators conducting operations on tribal lands may be subject to the Native American tribal court system. One or more of these factors may increase the Company's costs of doing business on Native American tribal lands and have an impact on the viability of its gas and oil exploration, production, gathering, processing and transportation operations on such lands.

FERC regulates interstate natural gas transportation (including storage). QEP owns three facilities that are directly regulated by FERC as either an interstate pipeline or a natural gas storage facility connected to interstate pipelines. Since the enactment of the Energy Policy Act of 2005, granting FERC increased penalty authority for non compliance, FERC has targeted various issues in the natural gas industry for compliance audits and investigations.

The transportation and sale for resale of natural gas in interstate commerce are regulated pursuant to the Natural Gas Act of 1938 (NGA) and the Natural Gas Policy Act of 1978. These statutes are administered by FERC. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act of 1989 deregulated natural gas prices for all "first sales" of natural gas, which includes all sales by QEP of its own production. All other sales of natural gas by QEP, such as those of natural gas purchased from third parties, remain jurisdictional sales subject to a blanket sales certificate under the NGA, which has flexible terms and conditions. Consequently, all of QEP's sales of natural gas currently may be made at market prices, subject to applicable contract provisions. QEP's jurisdictional sales, however, are subject to the future possibility of greater federal oversight, including the possibility that the FERC might prospectively impose more restrictive conditions on such sales. Conversely, sales of oil and condensate and NGL by QEP are made at unregulated market prices.

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. Requirements imposed by these authorities may be costly and time consuming and may result in delays in the commencement or continuation of the Company's exploration and production and midstream field services operations. Further, the public may comment on and otherwise seek to influence the permitting process, including through intervention in the courts. Accordingly, needed 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.

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. On September 12, 2011, President Obama sent a legislative package to Congress that included proposed legislation that, if enacted into law, would eliminate certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes included (i) the repeal of the percentage depletion allowance for oil and natural 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. President Obama's Proposed Fiscal Year 2012 Budget includes the foregoing proposals in substantially similar form. 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 natural gas exploration and development and increase the cost of exploration and development of natural gas and oil resources. Any such changes could have an adverse effect on QEP's financial position, results of operations and cash flows.

Federal and state hydraulic fracturing legislation or regulatory initiatives could increase QEP's costs and restrict its access to natural gas and oil reserves. 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 percent water and sand, with the remaining constituents consisting of 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. QEP obtains water for fracture stimulations from a variety of sources including industrial water wells and surface 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 natural gas and oil drilling and production operations described above, 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 natural gas and oil well design and operation. The Company supports disclosure of the contents of hydraulic fracturing fluids, and submits information regarding its wells to the national online disclosure registry, FracFocus (www.fracfocus.org). The EPA recently asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the federal Safe Drinking Water Act and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. In addition, legislation has 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. 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 legal restrictions or moratoria are adopted in areas where QEP operates, QEP could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling or stimulating wells in some areas.

In addition, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, 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 initial results expected to be available by late 2012 and final results by 2014. Moreover, the EPA recently announced on October 20, 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a wastewater treatment plant. In addition, the U.S. Department of Energy is conducting an investigation of practices the agency could recommend to better protect the environment from drilling employing hydraulic fracture stimulation. Also, the U.S. Department of the Interior has indicated it intends to issue new regulations regarding disclosure requirements and other mandates for hydraulic fracturing on federal lands. Additionally, certain members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources; the U.S. Securities & Exchange Commission 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 the U.S. 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. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

QEP's ability to produce natural gas and oil economically and in commercial quantities could be impaired if it is unable to acquire adequate supplies of water for its drilling operations or is unable to dispose of or recycle the water it uses at a reasonable cost and in accordance with applicable environmental rules. The hydraulic fracturing process on which QEP depends to produce commercial quantities of natural gas and oil requires the use and disposal of significant quantities of water. 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 in these regions. 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 natural 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, and all of which could have an adverse effect on QEP's operations and financial condition.

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 natural 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, and GHG emissions. QEP's ability to access and develop new natural gas reserves may be restricted by climate-change regulation. In legislative sessions bills have been pending 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 Environmental Protection Agency (EPA) has adopted final regulations for the measurement and reporting of GHG emitted from certain large facilities (25,000 tons/year of carbon dioxide (CO_2) equivalent) beginning with operations in 2010. The first such reports were filed with the EPA prior to March 31, 2011. 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 (100,000 metric tons per year of CO_2 equivalent emissions) will be required to obtain major source permits. In addition, several of the states in which QEP operates are considering various GHG registration and reduction programs. Carbon dioxide and other GHG regulation could increase the price of natural gas, restrict access to or the use of natural gas, and/or reduce natural gas demand. 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 natural gas. While future 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.

Derivatives regulation could increase QEP's liquidity risks by restricting its use of derivative instruments. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), which was passed by Congress and signed into law in July 2010, contains significant derivatives regulation, including a requirement that certain derivative transactions be cleared on exchanges, a requirement to post cash collateral (commonly referred to as "margin") for such derivative transactions, and strong business conduct standards. The Dodd-Frank Act exempts non-financial end-users using derivatives to hedge business risk from the central clearing requirements of the Dodd-Frank Act. The availability of the "end-user exemption" to exempt commercial end-users from the act's margin requirements depends on rules not yet finalized by the Commodities Futures and Trading Commission (CFTC). In January 2012, the CFTC released an updated timeline indicating that the CFTC would finalize these rules in the first quarter of 2012.

If an end-user exemption from the Dodd-Frank Act's margin requirements is not available to QEP, the Company could be required to post significant amounts of cash collateral with its dealer counterparties for its derivative transactions. A sudden, unexpected margin call triggered by rising commodity prices would have an immediate negative impact on QEP's liquidity, forcing QEP to divert capital from exploration, development and production activities. Requirements to post cash collateral could not only cause significant liquidity issues by reducing the Company's flexibility in using its cash and other sources of funds, such as its revolving credit facility, but could also cause QEP to incur additional debt. In addition, a requirement for QEP's counterparties to post cash collateral would likely result in additional costs being passed on to QEP, thereby decreasing the effectiveness of its commodity derivatives and its profitability. If the costs of complying with the clearing and margin requirements and business conduct rules under the Dodd-Frank Act significantly increase the costs of entering into commodity derivative transactions, QEP may reduce its commodity derivative program, which could increase its exposure to fluctuating commodity prices, increase the volatility of QEP's results of operations and reduce the predictability of the Company's cash flows, which in turn could adversely affect QEP's ability to plan for and fund capital expenditures.

Other Risks

General economic and other conditions impact QEP's results. QEP's results may also be negatively affected by: changes in global economic conditions; changes in regulation; availability and economic viability of gas and oil properties for sale or exploration; creditworthiness of counterparties; 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; terrorist attacks or acts of war; changes in business or financial condition; changes in credit ratings; and availability of financing for QEP.

The Company's pension plans are currently underfunded and may require large contributions, which may divert funds from other uses. Approximately 190 of QEP's employees participate in the closed defined benefit pension plan (QEP Resources, Inc. Retirement Plan). Over time, periods of declines in interest rates and pension asset values may result in a reduction in the funded status of the Company's pension plans. As of December 31, 2011 and 2010, QEP's pension plans were $59.9 million and $47.1 million underfunded. The underfunded status of QEP's pension plans may require that the Company make large contributions to such plans. QEP made cash contributions of $14.8 million and $1.6 million in 2011 and 2010, respectively, to its defined benefit pension plans and expect to make contributions of approximately $6.3 million to the funded plan in 2012. 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None

ITEM 2. PROPERTIES

EXPLORATION AND PRODUCTION

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

Southern Region

Haynesville/Cotton Valley

QEP Energy has approximately 50,800 net acres of Haynesville Shale lease rights in northwest Louisiana and additional lease rights that cover the Hosston and Cotton Valley formations. The depth of 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 for over a decade. As of December 31, 2011, QEP Energy had three operated rigs drilling in the project area.

Midcontinent

QEP Energy's Midcontinent properties 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 77,000 net acres of Woodford Shale lease rights in western Oklahoma. The true vertical depth to 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, 2011, QEP Energy had two operated rigs drilling in the project.

QEP Energy has approximately 38,700 net acres of Granite Wash/Atoka Wash lease rights in the Texas Panhandle and western Oklahoma and has been drilling vertical Granite Wash/Atoka Wash wells for over a decade. The true vertical depth to the top of the Granite Wash/Atoka Wash interval ranges from approximately 11,100 feet to 15,900 feet across QEP Energy's leasehold. In the past few years, QEP and other operators have drilled a number of successful horizontal wells in the Granite Wash/Atoka Wash play but have also drilled some wells with disappointing results. As of December 31, 2011, QEP Energy did not have any rigs drilling in the Granite Wash/Atoka Wash. In addition to its operated drilling programs, QEP Energy receives and participates in a large number of outside-operated well proposals.

Northern Region

Pinedale Anticline

In 2005, the Wyoming Oil and Gas Conservation Commission (WOGCC) approved 10 acre density drilling for Lance Pool wells on about 12,700 acres of QEP Energy's 17,872 acre (gross) Pinedale leasehold. The area approved for increased density corresponds to the currently estimated productive limits of QEP Energy core acreage in the field. In January 2008, the WOGCC approved five-acre density drilling for Lance Pool wells on about 4,200 gross acres of QEP Energy's Pinedale leasehold. The true vertical depth to the top of the Lance Pool tight gas sand reservoir interval ranges from 8,500 to 9,500 feet across QEP Energy's acreage. The Company currently estimates that up to 1,100 additional wells will be required to fully develop its Pinedale acreage on a combination of 5 and 10-acre density. In addition to QEP Energy's gross producing wells, QEP Energy had an overriding royalty interest only in an additional 21 wells at Pinedale.

Uinta Basin

The majority of Uinta Basin proved reserves are found in a series of vertically stacked, laterally discontinuous reservoirs at depths of 5,000 feet to deeper than 18,000 feet. QEP Energy owns interests in approximately 255,200 net leasehold acres in the Uinta Basin.

Rockies 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 the Rockies Legacy division. Exploration and development activity in 2011 includes wells in the Powder River and Greater Green River Basins in Wyoming and the Williston Basin in North Dakota.

QEP Energy has approximately 90,000 net acres of lease rights in the Williston Basin in western North Dakota, where the company is targeting the Bakken and Three Forks formations. The true vertical depth to 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, 2011, QEP Energy had one operated rig drilling in the project area.

Reserves – QEP Energy

At December 31, 2011 and 2010, approximately 91% and 88% of QEP Energy's estimated proved reserves were Company operated. Proved developed reserves represented 54% and 53% of the Company's total proved reserves at December 31, 2011 and 2010, respectively, while the remaining 46% and 47% of reserves were classified as proved undeveloped at December 31, 2011 and 2010. 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 reserves are summarized as follows:

	December 31, 2011				December 31, 2010			
	Natural Gas (Bcf)	Oil (Mbbl)	NGL (Mbbl)	Natural Gas Equivalents [1] (Bcfe)	Natural Gas (Bcf)	Oil (Mbbl)	NGL (Mbbl)	Natural Gas Equivalents [1] (Bcfe)
Proved developed reserves	1,538.3	32,955.5	38,388.1	1,966.3	1,404.8	25,115.6	9,342.9	1,611.5
Proved undeveloped reserves	1,211.1	34,559.3	38,169.0	1,647.5	1,208.1	27,161.1	8,026.6	1,419.2
Total proved reserves	2,749.4	67,514.8	76,557.1	3,613.8	2,612.9	52,276.7	17,369.5	3,030.7

(1) Oil and NGLs are converted to natural gas equivalents at the ratio of one bbl of oil or NGL to six Mcf of equivalent natural gas.

QEP Energy's reserve statistics for the years ended December 31, 2009 through 2011, are summarized below:

Year ended December 31,	Year End Resrves (Bcfe)	Natural Gas, Oil and NGL Production (Bcfe)	Reseve Life Index [1] (Years)
2009	2,746.9	189.5	14.5
2010	3,030.7	229.0	13.2
2011	**3,613.8**	**275.2**	**13.1**

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

Proved Reserves

Reserve and related information for 2011 and 2010 is presented consistent with the requirements of the SEC's rules for the Modernization of Oil and Gas Reporting, that we adopted December 31, 2009. These revised 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 prices for the prior 12 months (unless contractual arrangements designate the price) to be 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 14 of the consolidated financial statements included 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 at December 31, 2011 and 2010 are summarized below:

	2011		2010	
	(Bcfe)	**(% of total)**	(Bcfe)	(% of total)
Southern Region				
Haynesville/Cotton Valley	**782.9**	**22**	728.3	24
Midcontinent	**518.7**	**14**	442.2	15
Northern Region				
Pinedale Anticline	**1,531.0**	**42**	1,348.9	44
Uinta Basin	**393.6**	**11**	212.8	7
Rockies Legacy	**387.6**	**11**	298.5	10
Total QEP Energy	**3,613.8**	**100**	3,030.7	100

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, 2010 and 2009, because each new well drilled recovers incremental reserves that would otherwise be unrecoverable.

Proved Undeveloped Reserves

Significant changes to proved undeveloped reserves (PUDs) occurring during 2011 are summarized in the table below:

	2011
	(Bcfe)
Proved undeveloped reserves at January 1,	1,419.2
Transferred to proved developed reserves	(314.5)
Revisions to previous estimates	(37.2)
Extensions and discoveries	580.0
Proved undeveloped reserves at December 31, [1]	**1,647.5**

(1) All of QEP Energy's proved undeveloped reserves at December 31, 2011, are scheduled to be developed within five years from the date such locations were initially disclosed as proved undeveloped reserves, except for 217 Bcfe located within the northern portion of the Company's Pinedale Anticline leasehold in western Wyoming. Long-term development of natural gas reserves in Pinedale is governed by the BLM's September 2008, ROD on the FSEIS. Under the ROD, QEP Energy is allowed to drill and complete wells year-round in designated concentrated development areas. The ROD contains additional requirements and restrictions on the sequence of development, which requires the Company to develop its leasehold from the south to the north. These restrictions result in protracted, phased development that is beyond the control of the Company. The Company has an ongoing development plan and the financial capability to continue development in the manner estimated.

The costs incurred to continue the development of proved undeveloped reserves were approximately $533.6 million, $434.2 million and $216.1 million for the years ended December 31 2011, 2010 and 2009, respectively. The costs incurred in 2011 related to the drilling of PUDs in QEP development projects, which are discussed in Item 2 above. This investment resulted in the transfer in 2011 of 314.5 Bcfe of reserves from proved undeveloped to proved developed, representing 22% of the total proved undeveloped reserves that were recorded at December 31, 2010.

Estimated future development costs relating to the development of PUDs are projected to be approximately $614.9 million in 2012, $788.8 million in 2013 and $757.7 million in 2014. Estimated future development costs include capital spending on major development projects, some of which will take several years to complete. Proved undeveloped reserves related to major development projects will be reclassified to proved developed reserves when production commences.

Internal Controls Over Reserve Estimates, Technical Qualifications and Technologies Used

Estimates of proved gas and oil 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. We retained Ryder Scott Company, independent oil and gas reserve evaluation engineering consultants ("Ryder Scott"), to prepare the estimates of 100% of our reserves as of December 31, 2011, 2010 and 2009. The individual at Ryder Scott who was responsible for overseeing the preparation of our reserve estimates as of December 31, 2011, is a registered Professional Engineer in the State of Colorado and graduated with a Bachelors of Science degree in Geology from the University of Missouri at Rolla in 1976. The individual has over thirty 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 23.2 to this report.

The individual at QEP Resources 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 was our Chief Reservoir Engineer. Such individual is a member of the Society of Petroleum Engineers and graduated with a Bachelors of Science degree in Petroleum Engineering from Mississippi State University in 1993. This individual has 17 years experience in the Petroleum Industry, including 13 years reservoir engineering experience in most of the active domestic basins in the United States. A more detailed letter of the individual's professional qualifications has been filed as part of Exhibit 23.2 to this report.

The SEC's new rules expanded the technologies that a company can use to establish reserves. The SEC now allows use of techniques 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 has been field tested and has 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 our proved reserve estimates. The principal methodologies employed are performance, analogy or volumetric methods. All of the proved producing reserves attributable to producing wells and reservoirs were estimated by performance methods. Performance methods include, but may not be limited to, decline curve analysis which utilizes extrapolations of historical production and pressure data. Approximately 99 percent of QEP's proved developed non-producing and undeveloped reserves included in this Annual Report on Form 10-K were estimated by analogy and the remaining approximately one percent of the proved developed non-producing and undeveloped reserves were estimated by the volumetric method. Some combination of these methods is used to determine reserve estimates in substantially all of QEP's fields.

Refer to Note 14 of the consolidated financial statements included in Item 8 of Part II of this Annual Report 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, 2011, 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, Production Prices and Production Costs

The following table sets forth the net production volumes, the average net realized prices per Mcf of natural gas, per bbl of oil and per bbl of NGL produced, and the operating expenses per Mcfe for the years ended December 31, 2011, 2010 and 2009.

	Year Ended December 31,		
	2011	2010	2009
QEP Energy			
Volumes produced and sold			
Natural gas (Bcf)	**236.4**	203.8	168.7
Oil (Mbbl)	**3,741.3**	2,979.8	2,746.7
NGL (Mbbl)	**2,715.6**	1,225.8	705.0
Total production (Bcfe)	**275.2**	229.0	189.5
Average field-level price [(1)] [(2)]			
Natural gas (per Mcf)	**$ 3.95**	$ 4.18	$ 3.48
Oil (per bbl)	**86.20**	69.39	50.88
NGL (per bbl)	**47.76**	39.04	31.82
Lifting costs (per Mcfe)			
Lease operating expense	**$ 0.54**	$ 0.56	$ 0.67
Production taxes	**0.36**	0.34	0.31
Total lifting costs	**$ 0.90**	$ 0.90	$ 0.98

(1) During the year ended December 31, 2011, QEP revised its reporting of transportation and handling costs. Transportation and handling costs, previously netted against revenues, were recast on the Consolidated Income Statement from revenues to "Natural gas, oil and NGL transportation and other handling costs" for all periods presented. This change had no impact on net income. See Note 1 "Summary of Significant Accounting Policies," in Item 8, Part II of this Annual Report on Form 10-K, for additional information.

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

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

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
QEP Energy - Natural gas (Bcf)					
Southern Region					
Haynesville/Cotton Valley	**107.1**	79.3	46.9	**27.8**	32.4
Midcontinent	**32.9**	30.8	32.7	**2.1**	(1.9)
Northern Region					
Pinedale Anticline	**69.3**	65.1	58.9	**4.2**	6.2
Uinta Basin	**14.9**	14.9	16.7	**-**	(1.8)
Rockies Legacy	**12.2**	13.7	13.5	**(1.5)**	0.2
Total production	**236.4**	203.8	168.7	**32.6**	35.1

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

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
QEP Energy - Oil (Mbbl)					
Southern Region					
Haynesville/Cotton Valley	**51.0**	78.4	121.1	**(27.4)**	(42.7)
Midcontinent	**835.3**	644.3	775.1	**191.0**	(130.8)
Northern Region					
Pinedale Anticline	**583.8**	551.8	486.9	**32.0**	64.9
Uinta Basin	**866.7**	957.1	930.7	**(90.4)**	26.4
Rockies Legacy	**1,404.5**	748.2	432.9	**656.3**	315.3
Total production	**3,741.3**	2,979.8	2,746.7	**761.5**	233.1

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

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
QEP Energy - NGL (Mbbl)					
Southern Region					
Haynesville/Cotton Valley	**8.4**	5.5	3.3	**2.9**	2.2
Midcontinent	**1,371.2**	997.0	456.1	**374.2**	540.9
Northern Region					
Pinedale Anticline	**1,099.6**	-	-	**1,099.6**	-
Uinta Basin	**106.4**	121.5	151.2	**(15.1)**	(29.7)
Rockies Legacy	**130.0**	101.8	94.4	**28.2**	7.4
Total production	**2,715.6**	1,225.8	705.0	**1,489.8**	520.8

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

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
QEP Energy - Total Production (Bcfe)					
Southern Region					
Haynesville/Cotton Valley	**107.5**	79.8	47.7	**27.7**	32.1
Midcontinent	**46.2**	40.6	40.1	**5.6**	0.5
Northern Region					
Pinedale Anticline	**79.4**	68.5	61.8	**10.9**	6.7
Uinta Basin	**20.8**	21.4	23.2	**(0.6)**	(1.8)
Rockies Legacy	**21.3**	18.7	16.7	**2.6**	2.0
Total production	**275.2**	229.0	189.5	**46.2**	39.5

Productive Wells

The following table summarizes the Company's productive wells as of December 31, 2011. All of our wells are located in the United States.

	Natural gas		**Oil**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Southern Region						
Haynesville/Cotton Valley	1,413	669	7	4	1,420	673
Midcontinent	1,757	544	378	84	2,135	628
Northern Region						
Pinedale Anticline	613	377	-	-	613	377
Uinta Basin	660	469	1,651	194	2,311	663
Rockies Legacy	780	272	431	161	1,211	433
Total productive wells	5,223	2,331	2,467	443	7,690	2,774

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 natural gas and oil, and many natural gas wells also have allocated NGL volumes from processing, a well is categorized as either a natural 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. At the end of 2011, the Company had 90 gross wells with completions in more than one reservoir.

The Company also holds numerous overriding royalty interests in gas and oil wells, a portion of which are convertible to working interests after recovery of certain costs by third parties. After converting to working interests, these wells with overriding royalty interests will be included in the 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, 2011. "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 United States.

	Developed Acres (1)		Undeveloped Acres (2)		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Arkansas	33,733	9,837	5,369	3,362	39,102	13,199
Colorado	155,897	105,737	111,062	33,389	266,959	139,126
Kansas	28,994	12,894	52,379	17,205	81,373	30,099
Louisiana	72,351	60,036	6,483	6,064	78,834	66,100
Montana	14,294	7,637	306,619	52,843	320,913	60,480
New Mexico	99,802	71,859	32,619	12,600	132,421	84,459
North Dakota	38,033	10,804	212,652	88,756	250,685	99,560
Oklahoma	655,124	275,690	489,406	150,279	1,144,530	425,969
South Dakota	-	-	204,398	107,151	204,398	107,151
Texas	133,602	46,593	51,927	49,206	185,529	95,799
Utah	167,052	134,208	235,542	152,897	402,594	287,105
Wyoming	265,196	158,043	388,755	276,866	653,951	434,909
Other	2,429	735	158,475	43,357	160,904	44,092
Total	1,666,507	894,073	2,255,686	993,975	3,922,193	1,888,048

(1) Developed acreage is 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 natural gas and oil regardless of whether such acreage contains proved reserves.

A portion of the leases summarized in the preceding table will expire at the end of their respective primary terms unless the existing leases are renewed or production has been established from 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 acres subject to leases summarized in the preceding table that will expire during the periods indicated:

Leaseholds Expiring

	Undeveloped Acres Expiring	
	Gross	Net
12 months ending December 31,		
2012	56,351	36,718
2013	130,548	73,981
2014	67,140	47,618
2015	92,182	73,661
2016 and later	152,370	145,321

Drilling Activity

The following table summarizes the number of development and exploratory wells drilled on acreage owned by QEP during the years indicated.

	Developmental Wells				Exploratory Wells			
	Productive		Dry		Productive		Dry	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Year Ended December 31, 2011								
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**
Northern Region								
Pinedale	**105.0**	**71.6**	-	-	-	-	-	-
Uinta Basin	**176.0**	**6.3**	-	-	-	-	-	-
Rockies Legacy	**85.0**	**22.5**	-	-	-	-	-	-
Total	**678.0**	**176.7**	-	-	**6.0**	**1.7**	**6.0**	**2.6**
Year Ended December 31, 2010								
Southern Region								
Haynesville/Cotton Valley	85.0	44.0	-	-	33.0	16.2	1.0	1.0
Midcontinent	98.0	22.4	-	-	-	-	-	-
Northern Region								
Pinedale	103.0	72.5	-	-	-	-	-	-
Uinta Basin	188.0	23.9	-	-	-	-	-	-
Rockies Legacy	42.0	7.7	-	-	-	-	1.0	0.9
Total	516.0	170.5	-	-	33.0	16.2	2.0	1.9
Year Ended December 31, 2009								
Southern Region								
Haynesville/Cotton Valley	82.0	61.6	-	-	8.0	1.8	-	-
Midcontinent	76.0	24.8	-	-	-	-	-	-
Northern Region								
Pinedale	96.0	58.6	-	-	-	-	-	-
Uinta Basin	7.0	6.7	-	-	-	-	-	-
Rockies Legacy	12.0	2.8	1.0	-	4.0	1.9	-	-
Total	273.0	154.5	1.0	-	12.0	3.7	-	-

The following table presents operated and non-operated well activity at December 31, 2011 as well as completions for the year ended December 31, 2011:

	Operated						Non-operated					
	Completions		Drilling		Waiting on completion		Completions		Drilling		Waiting on completion	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Southern Region												
Haynesville/Cotton Valley	38.0	30.3	8.0	6.9	21.0	10.6	59.0	8.1	-	-	4.0	0.3
Midcontinent	29.0	21.8	2.0	1.3	4.0	2.4	192.0	17.8	13.0	1.7	11.0	2.1
Northern Region												
Pinedale	105.0	71.6	4.0	2.4	24.0	17.3	-	-	-	-	-	-
Uinta Basin	7.0	5.9	1.0	1.0	2.0	2.0	169.0	0.4	2.0	0.1	-	-
Rockies Legacy	23.0	20.1	-	-	4.0	3.7	62.0	2.4	13.0	0.4	20.0	4.2

Delivery Commitments

The Company sells NGLs under a term sales agreement that contains a delivery commitment for 8,500 barrels per day of NGL derived from several of QEP Field Services' gas processing facilities in the Northern Region. The agreement, which was 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 its gas processing facilities and projected processing volumes are adequate to satisfy its delivery commitments under this agreement.

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

Period	Delivery Commitments (millions of MMBtu)
2012	**186.7**
2013	**75.8**
2014	**28.9**
2015	**18.8**
2016	**-**
After 2016	-

These commitments are physical delivery obligations with prices related to the prevailing index prices for natural gas at the time of delivery. None of these commitments require the Company to deliver natural 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 natural gas production is not sufficient to satisfy its term sales commitments, the Company believes it can purchase sufficient volumes of natural gas in the market at index-related prices to satisfy its commitments.

In addition, none of the Company's production from QEP Energy 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 "Risk Factors" in this Annual Report on Form 10-K.

MIDSTREAM FIELD SERVICES – QEP Field Services

QEP Field Services owns 1,905 miles of gathering lines in Utah, Wyoming, Colorado, Louisiana and North Dakota. At December 31, 2011 QEP Field Services also owns processing plants, which remove NGL from the natural gas stream, that have an aggregate processing capacity, of 1.37 Bcf per day of unprocessed natural gas. In addition, QEP Field Services owns treating facilities in northwest Louisiana, which remove CO_2 from the natural gas stream, that have an aggregate treating capacity of 600 MMcf per day of untreated natural gas. QEP Field Services also owns compression facilities and field dehydration and measurement systems. The 21-mile, 20-inch diameter pipeline owned by Rendezvous Pipeline can deliver up to 300 MMcf of natural gas per day to the Kern River Pipeline. QEP Field Services partnership facilities include the RGS system, consisting of 300 miles of gathering lines and associated field equipment, the UBFS system, which consists of 78 miles of gathering lines and associated field equipment and the Three Rivers system, which consists of 52 miles of gathering lines and associated field equipment.

In January 2011, QEP Field Services put into service the 150 MMcf per day cryogenic Iron Horse processing plant, an expansion of its Stagecoach processing complex in the Uinta Basin of eastern Utah. The plant predominantly provides fee-based processing services to third parties. In July 2011, QEP Field Services commissioned the 420 MMcf per day Blacks Fork II cryogenic processing plant, an expansion of its Blacks Fork processing complex located in the Green River Basin of southwestern Wyoming. The Blacks Fork complex is about 100 miles south of QEP's operations at Pinedale. QEP expects that the Blacks Fork II plant at full capacity will be able to extract an incremental net 16,000 bbls per day of NGL.

ENERGY MARKETING – QEP Marketing

QEP Marketing, through its wholly owned subsidiary Clear Creek Storage Company, LLC, owns and operates an underground gas storage reservoir in southwestern Wyoming. The reservoir has a gas storage capacity of approximately 8 Bcf, comprised of an inventory of approximately 4 Bcf of QEP Marketing-owned cushion gas and working gas storage capacity of about 4 Bcf.

ITEM 3. LEGAL PROCEEDINGS

QEP is involved in various commercial and regulatory claims and litigation and other legal proceedings that arise in the ordinary course of its business. Management does not believe any of them will have a material adverse effect on the Company's financial position, results of operations or cash flows. A liability is recorded for a loss contingency when its occurrence is probable and damages can be reasonably estimated based on the anticipated most likely outcome. Disclosures are provided for contingencies reasonably likely to occur which would have a material adverse effect on the Company's financial position, results of operations or cash flows. Some of the claims involve highly complex issues relating to liability, damages and other matters subject to substantial uncertainties and, therefore, the probability of liability or an estimate of loss cannot be reasonably determined.

Environmental Claims

United States of America v. QEP Field Services, Civil No. 208CV167, U.S. District Court for Utah. The U.S. Environmental Protection Agency (EPA) alleges that QEP Field Services (f/k/a Questar Gas Management) violated the Clean Air Act (CAA) and seeks substantial penalties and a permanent injunction involving the manner of operation of five compressor stations located in the Uinta Basin of eastern Utah. Individual members of the Ute Indian Tribe's Business Committee intervened as co-plaintiffs asserting the same CAA claims as the federal government. EPA contends that the potential to emit, on a hypothetically uncontrolled basis, for these facilities renders them "major sources" of emissions for criteria and hazardous air pollutants even though controls were installed and operated by QEP Field Services. Categorization of the facilities as "major sources" affects the particular regulatory program and requirements applicable to those facilities. EPA claims that QEP Field Services failed to obtain the necessary major source pre-construction or modification permits, and failed to comply with hazardous air-pollutant regulations for monitoring, testing and reporting, among other requirements. QEP Field Services contends that its facilities have pollution controls installed, as part of their operational design, that reduce their actual air emissions below major source thresholds, rendering them subject to different regulatory requirements applicable to non-major sources. QEP Field Services has vigorously defended against EPA's claims, and believes that the major source permitting and regulatory requirements at issue can be legally avoided by applying EPA's prior permitting practice for similar facilities elsewhere in Indian Country, among other defenses. Because of the complexities and uncertainties of this legal dispute, it is difficult to predict all reasonably possible outcomes; however, management believes the Company has accrued a reasonable loss contingency that is an immaterial amount, for the anticipated most likely outcome.

QEP Energy v. U.S. Environmental Protection Agency, No. 09-9538, U.S. Court of Appeals for the 10th Circuit. On July 10, 2009, QEP Energy filed a petition with the U.S. 10th Circuit Court of Appeals challenging an administrative compliance order dated May 12, 2009 (Order), issued by EPA which asserts that QEP Energy's Flat Rock 14P well in the Uinta Basin and associated equipment is a major source of hazardous air pollutants and its operation fails to comply with certain regulations of the CAA. The Order required immediate compliance. QEP Energy denied that the drilling and operation of the 14P well and associated equipment violated any provisions of the CAA. QEP and EPA entered into an administrative order on consent, effective June 17, 2011, resolving all disputes associated with prospective CAA compliance at the Flat Rock 14P well. Among other matters, the order requires installation of pollution control equipment to destroy vapors from the well's dehydration equipment and ongoing monitoring and reporting associated with operation of that control equipment.

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, 2012, QEP had 7,793 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 Board of Directors. The Company expects that cash dividends will continue to be paid in the future. Following is a summary of the high and low sales price per share of QEP's common stock on the NYSE and quarterly dividends paid per share:

	High price	Low price	Dividend
		(per share)	
2011			
First quarter	$ 42.00	$ 35.78	$ 0.02
Second quarter	43.70	37.11	0.02
Third quarter	45.20	26.52	0.02
Fourth quarter	38.44	23.56	0.02
			$ 0.08
2010			
First quarter [(1)]	$ -	$ -	$ -
Second quarter [(1)]	-	-	-
Third quarter	35.15	27.90	0.02
Fourth quarter	38.33	29.54	0.02
			$ 0.04

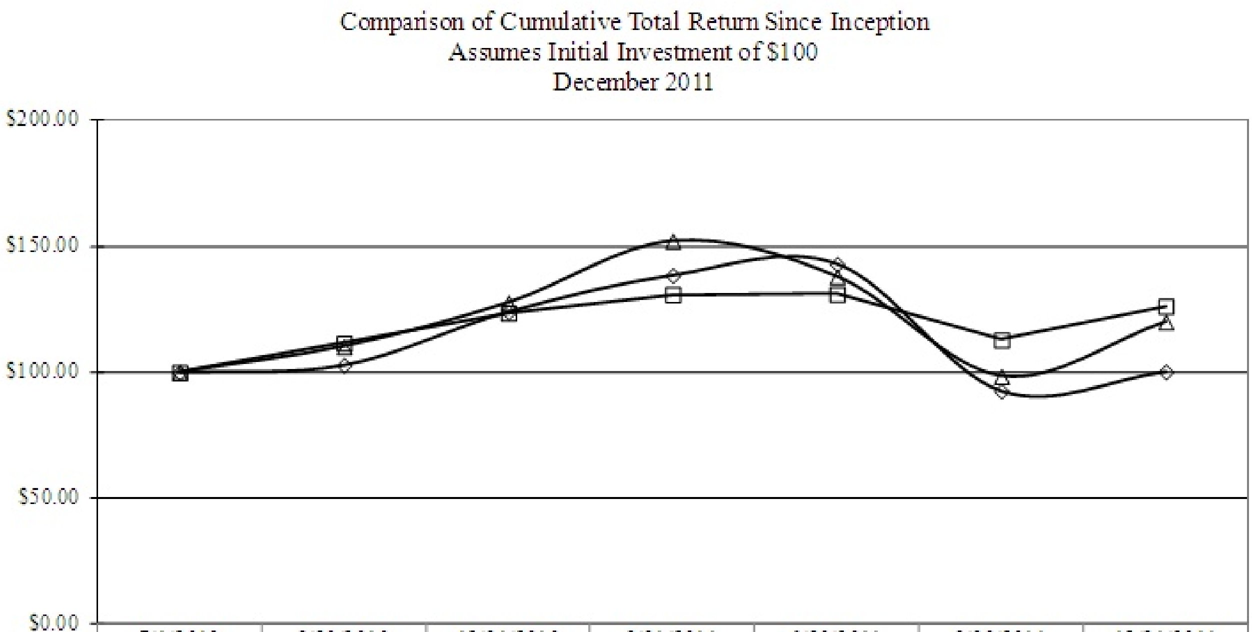
(1) Public trading of the common stock of the Company commenced on July 1, 2010.

Stockholder Return Performance Presentation

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 common stock, the S&P 500 Index and the Company's peer group as of July 1, 2010, which is the date when QEP's common stock began trading on the NYSE;
- Investment in the Company's peer group was weighted based on the stock market capitalization of each individual company within the peer group at the beginning of each period for which a return is indicated; and
- Dividends were reinvested on the relevant payment dates.

QEP's peer group, as defined, consists of the following companies: Cabot Oil & Gas Corporation, Cimarex Energy Company, Denbury Resources Inc., EOG Resources, Inc., Forest Oil Corporation, Newfield Exploration Company, Noble Energy, Inc., Pioneer Natural Resources Company, Plains Exploration & Production Company, Quicksilver Resources, Inc., Range Resources Corporation, Southwestern Energy Company, Ultra Petroleum Corporation and Whiting Petroleum Corporation. Petrohawk Energy Corporation was removed from the peer group in 2011, due to its acquisition by BHP Billington. Management believes this peer group provides a meaningful comparison based upon the Company's review of asset size, geographic location of assets, market capitalization, revenues, culture and performance, among other things.



	7/1/2010	9/30/2010	12/31/2010	3/31/2011	6/30/2011	9/30/2011	12/31/2011
QEP Resources, Inc.	100.00	102.90	124.03	138.56	143.03	92.61	100.30
S&P 500 Index - Total Returns	100.00	111.65	123.66	130.98	131.11	112.93	126.27
Peer Group	100.00	110.30	127.71	152.27	138.07	98.46	120.07

Purchases of equity securities by the issuer and affiliated purchasers

The following repurchases of QEP shares were made by an affiliated purchaser, QEP Resources Education Foundation, during the fourth quarter of 2011:

Period	Total number of shares purchased [(1)]	Weighted-average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Maximum number of shares that may yet be epurchased under the plans or programs
October 1, 2011 - October 31, 2011	-	$ -	-	-
November 1, 2011 - November 30, 2011	7,475	$ 37.3425	-	-
December 1, 2011 - December 31, 2011	-	$ -	-	-
	7,475	$ 37.3425	-	-

[(1)] QEP Resources Education Foundation, an affiliated purchaser, purchased the shares in open-market transactions. These purchases were not made pursuant to a publicly announced plan or program.

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ITEM 6. SELECTED FINANCIAL DATA

Selected financial data for the five years ended December 31, 2011, is provided in the table below. Refer to Item 7 and Item 8 in Part II of this annual report for discussion of facts affecting the comparability.

	Year Ended December 31,				
	2011	2010	2009	2008	2007
			(in millions)		
Results of Operations [1]					
Revenues [2]	**$ 3,159.2**	$ 2,300.6	$ 2,011.2	$ 2,360.9	$ 1,713.7
Operating income	**505.9**	545.3	585.5	933.2	584.1
Income from continuing operations	**270.4**	285.9	215.4	520.6	361.6
Discontinued operations, net of income tax	-	43.2	80.7	73.9	59.2
Net income attributable to QEP	**267.2**	326.2	293.5	585.5	420.8
Earnings per common share attributable to QEP					
Basic from continuing operations	**$ 1.51**	$ 1.61	$ 1.23	$ 2.96	$ 2.11
Basic from discontinued operations	-	0.25	0.46	0.43	0.34
Basic total	**$ 1.51**	$ 1.86	$ 1.69	$ 3.39	$ 2.45
Diluted from continuing operations	**$ 1.50**	$ 1.60	$ 1.21	$ 2.90	$ 2.05
Diluted from discontinued operations	-	0.24	0.46	0.42	0.34
Diluted total	**$ 1.50**	$ 1.84	$ 1.67	$ 3.32	$ 2.39
Dividends	**$ 0.08**	$ 0.04	$ -	$ -	$ -
Weighted-average common shares outstanding					
Used in basic calculation	**176.5**	175.3	174.1	172.8	172.0
Used in diluted calculation	**178.4**	177.3	176.3	176.1	175.9
Financial Position					
Total Assets at December 31,	**$ 7,442.7**	$ 6,785.3	$ 6,481.4	$ 6,342.7	$ 3,821.6
Capitalization at December 31,					
Long-term debt	**1,679.4**	1,530.8	1,348.7	1,299.1	499.3
Total equity	**3,352.1**	3,063.1	2,808.7	2,779.4	1,860.1
Total Capitalization	**$ 5,031.5**	$ 4,593.9	$ 4,157.4	$ 4,078.5	$ 2,359.4
Cash Flow From Continuing Operations					
Net cash provided by operating activities	**$ 1,292.6**	$ 997.5	$ 1,149.4	$ 1,224.7	$ 807.0
Capital expenditures	**(1,431.1)**	(1,469.0)	(1,196.9)	(2,136.7)	(838.9)
Net cash used in investing activities	**(1,422.9)**	(1,390.5)	(1,146.4)	(2,021.0)	(867.9)
Net cash provided by (used in) financing activities	**130.3**	373.7	(8.8)	818.7	44.1
Non-GAAP Measures					
Adjusted EBITDA [3]	**$ 1,386.6**	$ 1,140.5	$ 1,165.5	$ 1,310.7	$ 890.7

(1) QEP completed a Spin-off from Questar in June 2010 as discussed in more detail in the Explanatory Note in Part I, Item 1 of this Annual Report on Form 10-K. As a result of the Spin-off, Wexpro's financial results have been reflected as discontinued operations and all prior periods have been recast.

(2) During the year ended December 31, 2011, QEP revised its reporting of transportation and handling costs. Transportation and handling costs, previously netted against revenues, have been recast on the Consolidated Income Statement from revenues to "Natural gas, oil and NGL transportation and other handling costs" for all periods presented. This change has no imapct on net income. See Note 1 "Summary of Significant Accounting Policies," in Item 8, Part II of this Annual Report on Form 10-K, for additional information.

(3) Adjusted EBITDA is a non-GAAP measure. Management defines Adjusted EBITDA as net income before the following items: discontinued operations, unrealized gain and losses on basis-only swaps, gains and losses from asset sales, interest and other income, income taxes, interest expense, separation costs, loss on early extinguishment of debt, depreciation, depletion and amortization, abandonment and impairment, and exploration expense. 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 make distributions to shareholders, and an important measure for comparing the Company's financial performance to other gas and oil producing companies. In addition, Adjusted EBITDA is a part of the Company's debt covenants as defined in its revolving credit agreement.

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

	Year Ended December 31,				
	2011	2010	2009	2008	2007
			(in millions)		
Adjusted EBITDA					
Net income attributable to QEP	**$ 267.2**	$ 326.2	$ 293.5	$ 585.5	$ 420.8
Net income attributable to noncontrolling interest	**3.2**	2.9	2.6	9.0	$ -
Net income	**270.4**	329.1	296.1	594.5	420.8
Discontinued operations, net of tax	**-**	(43.2)	(80.7)	(73.9)	(59.2)
Income from continuing operations	**270.4**	285.9	215.4	520.6	361.6
Unrealized gain (loss) on basis-only swaps	**(117.7)**	(121.7)	164.0	79.2	(5.7)
Net (gain) loss from asset sales	**(1.4)**	(12.1)	(1.5)	(60.4)	0.6
Interest and other income	**(4.1)**	(2.3)	(4.5)	(10.2)	(7.8)
Income taxes	**154.4**	167.0	117.6	283.6	211.3
Interest expense	**90.0**	84.4	70.1	61.7	33.6
Separation costs	**-**	13.5	-	-	-
Loss from early extinguishment of debt	**0.7**	13.3	-	-	-
Depreciation, depletion and amortization	**765.4**	643.4	559.1	361.5	263.9
Abandonment and impairment	**218.4**	46.1	20.3	45.4	11.2
Exploration expenses	**10.5**	23.0	25.0	29.3	22.0
Adjusted EBITDA	**$ 1,386.6**	$ 1,140.5	$ 1,165.5	$ 1,310.7	$ 890.7

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

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

The following information updates the discussion of QEP's financial condition provided in its 2010 Form 10-K filing, and analyzes the changes in the results of operations between the years ended December 31, 2011 versus December 31, 2010 and December 31, 2010 versus December 31, 2009. During the year ended December 31, 2011, QEP revised its reporting of transportation and handling costs. Transportation and handling costs, previously netted against revenues, have been recast on the Consolidated Income Statement from revenues to "Natural gas, oil and NGL transportation and other handling costs for all periods presented. The impact of this revision is immaterial to the accompanying financial statements and has no effect on income. See Note 1 "Summary of Significant Accounting Policies," in Item 8, Part II of this Annual Report on Form 10-K, for additional information.

OVERVIEW

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

- QEP Energy Company (QEP Energy) acquires, explores for, develops and produces natural gas, oil, and NGL;
- QEP Field Services Company (QEP Field Services) provides midstream field services, including natural gas gathering and processing, compression and treating services, for affiliates and third parties; and
- QEP Marketing Company (QEP Marketing) markets affiliate and third-party natural gas and oil, provides risk-management services, and owns and operates an underground gas-storage reservoir.

Reincorporation Merger and Spin-off

Effective May 18, 2010, Market Resources, then a wholly owned subsidiary of Questar, merged with and into QEP, a Delaware corporation and a newly formed, wholly owned subsidiary of Questar, in order to reincorporate in the State of Delaware. 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 to existing Questar stockholders all of the shares of common stock of QEP in a tax-free, pro-rata spin-off, establishing QEP as an independent, publicly traded company. In connection with the Spin-off, QEP distributed 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.

Outlook

The Company has substantial acreage positions and operations in some of North America's most important hydrocarbon resource plays, including the Bakken/Three Forks, Pinedale, Haynesville and Woodford "Cana" 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. Resource plays allow the Company the opportunity to gain considerable operational efficiencies through high density and 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 organic production and reserve growth. QEP believes that it has one of the lowest cash cost structures among its exploration and production company peers. However, in certain of its resource plays, the Company has experienced rising completed well costs, which could impact future drilling plans.

While predominantly a natural gas producer, the Company has increased its focus on growing the relative proportion of crude oil and NGL production in its exploration and production business. QEP Energy oil and NGL production increased by approximately 54% during the year ended December 31, 2011 to 6,456.9 Mbbl, and oil and NGL revenue accounted for approximately 29% of net production revenues (including realized gains and losses on all settled derivative contracts) during the year ended December 31, 2011, compared to 19% and 12% during the years ended December 31, 2010 and 2009, respectively. QEP Energy oil and NGL production increased by approximately 22% during the year ended December 31, 2010 when compared to the 2009 period. The increase in NGL sales volumes during 2011 was a result of the fee-based processing agreement entered into with QEP Field Services effective August 1, 2011, shortly after the start-up of the Blacks Fork II plant in July 2011 and the liquids recovered for QEP Energy by third party processers associated with development of liquids-rich plays in the Midcontinent and in the Bakken/Three Forks formations. The Company has allocated approximately 88% of its forecasted 2012 drilling and completion capital expenditure budget to oil and liquids-rich natural gas plays due to current depressed natural gas prices and the natural gas forward price.

While QEP believes that it can grow its production and reserves from its extensive inventory of drilling locations, the Company also evaluates acquisition opportunities that might have the potential to create significant long-term value. QEP believes that its experience, expertise and substantial presence in the Southern and Northern Regions, combined with its low-cost operating structure and financial strength, enhance its ability to pursue acquisition opportunities in those geographic areas.

The Company also owns and operates gathering and transmission pipelines and natural gas processing and treatment facilities in many of its core producing areas, which allows the Company to promptly connect its wells, better control its costs, and generate a significant revenue stream by providing gathering and processing services to third parties. Net income from QEP's midstream business accounted for approximately 58% of the Company's total net income from continuing operations attributable to QEP during the year ended December 31, 2011, compared to 32% and 33% during the years ended December 31, 2010 and 2009. QEP's midstream net income as a percentage of total Company net income increased in 2011 due in part to impairment charges at QEP Energy which decreased its share of total Company net income as compared to prior periods.

Financial and Operating Results

During the year ended December 31, 2011, QEP had strong production growth from QEP Energy, its exploration and production business, and QEP Field Services, its gathering and processing business. Although crude oil and NGL prices decreased in the second half of 2011 from the first half of 2011, QEP Energy benefitted from higher production and higher crude oil and NGL prices during the year ended December 31, 2011, as compared to the 2010 and 2009 periods. QEP Field Services benefitted during the year ended December 31, 2011, from the Iron Horse plant having three full quarters of operations, the commencement of the Blacks Fork II processing plant in the second half of 2011 and continued robust gas processing margins.

During the years ended December 31, 2011, 2010, and 2009, QEP Energy reported production of 275.2 Bcfe, 229.0 Bcfe and 189.5 Bcfe, respectively. During the year ended December 31, 2011, the Southern and Northern Regions contributed 56% and 44%, respectively, of total equivalent production. QEP Energy continues to focus on the controllable cash cost of production per Mcfe. The Company defines cash cost of production as the sum of lease operating expense, general and administrative expense, a portion of total QEP interest expense that is allocated to QEP Energy based on intercompany agreements and production taxes. Cash operating costs for QEP Energy were $1.56 per Mcfe during the year ended December 31, 2011 compared to $1.58 per Mcfe and $1.68 per Mcfe for the years ended December 31, 2010 and 2009. The decrease was the result of increased production volumes partially offset by higher overall production costs. QEP Energy reported record production of 275.2 Bcfe in 2011 and all divisions, other than the Uinta Basin, recorded production that was greater than in 2010. Year-end proved reserves increased by 19% over the prior year to 3.61 Tcfe.

QEP Field Services reported gathering system throughput of 1.4 million MMBtu per day during the year ended December 31, 2011, up from 1.3 million MMBtu per day and 1.1 million MMBtu per day for the years ended December 31, 2010 and 2009. During the year ended December 31, 2011, QEP Field Services reported a 42% increase in NGL sales volumes to a total of 141.8 million gallons. The increase in NGL sales volumes along with a 38% increase in the per unit NGL margin (NGL revenue less fuel and shrinkage and transportation and handling costs) resulted in a 95% increase to the keep-whole processing margin during the year ended December 31, 2011.

During the first quarter of 2011, QEP Field Services commenced operations of the 150 MMcf per day cryogenic Iron Horse processing plant, an expansion of its Stagecoach processing complex in the Uinta Basin of eastern Utah. This plant predominantly provides fee-based processing services to third-parties. During the third quarter of 2011, QEP Field Services commissioned the 420 MMcf per day Blacks Fork II cryogenic processing plant, an expansion of its Blacks Fork processing complex located in the Green River Basin of southwestern Wyoming. The Blacks Fork complex is about 100 miles south of QEP's operations at Pinedale. QEP expects that the Blacks Fork II plant at full capacity will be able to extract an incremental net 16,000 Bbls per day of NGL.

During the third quarter of 2011, QEP entered into a new revolving credit facility, which matures in August 2016, and replaced the previous $1.0 billion credit facility. The terms of the new credit facility provide for loan commitments of $1.5 billion from a syndicate of financial institutions. The new credit facility provides for borrowings at short-term interest rates and contains customary covenants and restrictions. The agreement also contains provisions which 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.

During the fourth quarter of 2011, QEP recorded a non-cash price-related impairment charge of $195.2 million on some of its mature, dry gas, and higher cost properties in both the Northern and Southern Regions. The impairment charge related to the reduced value of these areas resulting from lower natural gas prices and the current forward curve for natural gas prices. The assets were written down to their estimated fair values. Of the $195.2 million impairment charge, $163.5 million were related to properties in the Northern Region with the remaining $31.7 million related to properties in the Southern Region. See Item 8, footnote 1, "Summary of Significant Accounting Policies", of this Annual Report on Form 10-K, for additional information regarding the impairment.

Factors Affecting Results of Operations

Oil and Natural Gas Prices

Historically, prices received for QEP's natural gas, NGL and crude oil production have been volatile and unpredictable, and that volatility is expected to continue. In recent years, the domestic natural gas supply has grown faster than natural gas demand, driven by advances in technology, including horizontal drilling and hydraulic fracturing, which have allowed producers to extract increasing amounts of natural gas from shale, tight sand formations, and other unconventional reservoirs. Increased natural gas supply has put downward pressure on natural gas prices, while concern about the global economy and other factors has caused the price of crude oil to decrease in the second half of 2011 from the first half of 2011, although they remain higher during the year ended December 31, 2011 than comparable 2010 and 2009 prices. Changes in the market prices for crude oil, natural gas and NGL directly impact many aspects of QEP's business, including its financial condition, revenues, results of operations, liquidity, rate of growth, costs of goods and services required to drill and complete wells, and the carrying value of its oil and natural gas properties. For example, despite a 16% increase in natural gas production during the year ended December 31, 2011, natural gas revenues increased by only 3% due to significantly lower net realized natural gas prices. Similarly, during the year ended December 31, 2010, natural gas production increased 21%, yet natural gas revenues increased by only 2% due to lower net realized natural gas prices.

QEP uses commodity derivatives to reduce the variability of the prices QEP receives for a portion of its production and to provide a minimum revenue stream. In general, QEP plans to hedge approximately 50% of its forecasted production by the end of the first quarter of the current year. As of December 31, 2011, QEP Energy had approximately 49% of its forecasted 2012 natural gas, oil and NGL production covered with fixed-price swaps or costless collars, assuming 2012 annual production of 307.5 Bcfe. See "Quantitative and Qualitative Disclosures about Market Risk – Commodity Derivative Transactions" for further details concerning QEP's commodity derivatives transactions. In addition, as a result of the continued spread between oil and natural gas prices, the Company has allocated approximately 88% of its forecasted 2012 drilling and completion capital expenditure budget to oil and liquids-rich natural gas projects in its portfolio.

Unrealized Derivative Gains and Losses

Unrealized gains and losses that result from mark-to-market valuations of derivative positions that are not accounted for as cash flow hedges were reflected as unrealized commodity derivative gains or losses in the Company's income statement during the years ended December 31, 2011, 2010 and 2009. In addition, the Company has elected to discontinue hedge accounting beginning January 1, 2012 and future unrealized gains and losses that result from mark-to-market valuations of all derivative positions will be reflected as unrealized commodity derivative gains or losses in the Company's income statement. See Item 8, footnote 1, "Summary of Significant Accounting Policies," of this annual report on Form 10-K for additional information regarding the discontinuance of hedge accounting. Payments due to or from counterparties in the future on these derivatives will typically be offset by corresponding changes in prices ultimately received from the sale of QEP's production. 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.

Blacks Fork II Processing Plant

The completion and start-up of the new Blacks Fork II processing plant resulted in increased NGL production in QEP Field Services and QEP Energy in 2011. As part of the agreement, QEP Energy and QEP Field Services recorded line pack for the NGL line-fill requirements which is recorded as inventory on each of the respective company's balance sheet at December 31, 2011.

In conjunction with the start up of the Blacks Fork II plant, QEP Energy entered into a fee-based processing agreement with QEP Field Services to process QEP Energy's share of Pinedale gas. As a result, about 46% of the NGL recovered at the Blacks Fork II plant will be accounted for as NGL production in QEP Energy, with about 40% included in the keep-whole volumes in QEP Field Services. The remaining 14% relates to non-QEP royalty volumes.

Global Economy and the European Debt Crisis

QEP remains hopeful for a continued recovery of the global economy, however, 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, the United States federal budget deficit, and commodity prices. QEP expects natural gas prices to remain low in the United States if the natural gas drilling rig counts remain near current levels, natural gas storage remains high and natural gas production continues to grow. QEP expects oil prices to remain at or above current levels if the global economy continues its recovery. Disruption to the global oil supply system or other factors, could trigger oil price volatility with sharp increases in the crude oil price that could be followed by sharp declines in the price the Company may receive for its oil production. Because of the global economic outlook and the uncertainty around the commodity pricing environment, QEP continues to plan its capital spending program and financial flexibility appropriately.

Potential for Future Asset Impairments

The United States natural gas market remains weak. A further decrease in forward natural gas prices during 2012 could result in additional impairment charges. Certain of the Company's properties have significant natural gas reserves and therefore are sensitive to declines in natural gas prices. These assets are at risk of impairment if future NYMEX Henry Hub natural gas prices experience further decline. 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 and gas 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 natural gas prices alone could result in an impairment of properties that are sensitive to declines in natural gas prices. A significant drop in oil prices could also trigger impairment. For additional information see Item 1A "Risk Factors" and see Item 8. Note 1 "Significant Accounting Policies."

RESULTS OF OPERATIONS

Net Income

QEP Resources net income from continuing operations attributable to QEP in 2011 was $267.2 million or $1.50 per diluted share, compared to $283.0 million or $1.60 per diluted share in 2010. The decrease in 2011 was due to the $99.2 million, or 49%, decline in QEP Energy's net income, partially offset by a $63.4 million, or 70%, increase in QEP Field Services' net income. QEP Energy's net income declined in 2011 because of a non-cash, price-related impairment charge of $195.2 million in the fourth quarter of 2011 on some of its mature, dry gas, and higher cost properties in both the Northern and Southern Regions. Offsetting the decline at QEP Energy, QEP Field Services' increase in net income was driven by higher gathering and processing margins and increased throughput volumes. QEP Resources net income from continuing operations attributable to QEP in 2010 was $70.2 million, or 33% higher than the 2009 period. The increase in 2010 net income was primarily driven by increased net income at both QEP Energy and QEP Field Services. QEP Energy's 2010 increase in net income was the result of higher production and higher net realized crude oil and NGL prices in 2010, partially offset by lower net realized natural gas prices. QEP Field Services' 2010 increase in net income was due to higher gathering and processing margins and increased throughput volumes. Following are comparisons of net income from continuing operations attributable to QEP by line of business:

	Year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
			(in millions)		
QEP Energy	**$ 104.7**	$ 203.9	$ 134.9	**$ (99.2)**	$ 69.0
QEP Field Services	**154.5**	91.1	69.4	**63.4**	21.7
QEP Marketing and other	**8.4**	6.7	8.5	**1.7**	(1.8)
QEP Resources	**(0.4)**	(18.7)	-	**18.3**	(18.7)
Net income from continuing operations attributable to QEP	**$ 267.2**	$ 283.0	$ 212.8	**$ (15.8)**	$ 70.2
Earnings per diluted share from continuing operations	**$ 1.50**	$ 1.60	$ 1.21	**$ (0.10)**	$ 0.39
Average diluted shares	**178.4**	177.3	176.3	**1.1**	1.0

Adjusted EBITDA

Management believes Adjusted EBITDA (a non-GAAP measure) is an important measure of the Company's cash flow and liquidity and an important measure for comparing the Company's financial performance to other gas and oil producing companies. Management defines Adjusted EBITDA as net income before the following items: depreciation, depletion and amortization, abandonment and impairment, interest and other income, interest expense, separation costs, loss on early extinguishment of debt, income taxes, unrealized gain and losses on basis-only swaps, discontinued operations, gains and losses from assets sales, and exploration expense. During the year ended December 31, 2011, QEP revised its reporting of transportation and handling costs to align with industry practice and GAAP. This revised disclosure does not change current or prior period disclosure of net income and Adjusted EBITDA. For additional information, see Item 8, Note 1 "Significant Accounting Policies" for additional details. Following are comparisons of Adjusted EBITDA by line of business:

	Year Ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
			(in millions)		
QEP Energy	**$ 1,057.5**	$ 926.2	$ 988.0	**$ 131.3**	$ (61.8)
QEP Field Services	**320.3**	203.9	162.6	**116.4**	41.3
QEP Marketing and other	**8.8**	10.4	14.9	**(1.6)**	(4.5)
Total Adjusted EBITDA	**$ 1,386.6**	$ 1,140.5	$ 1,165.5	**$ 246.1**	$ (25.0)

Adjusted EBITDA increased 22% to $1,386.6 million for the year ended December 31, 2011, compared to $1,140.5 million in the 2010 period, despite an 11% decrease in net realized natural gas prices. The impact of lower net realized natural gas prices during the year ended December 31, 2011 was offset by a 20% increase in total production, 30% higher net realized crude oil prices and 22% higher net realized NGL prices in QEP Energy, along with increased gathering margins (22% higher) and processing margins (93% higher) in QEP Field Services. Adjusted EBITDA decreased only 2% during the year ended December 31, 2010 from the $1,165.5 million during the year ended December 31, 2009, despite a decrease in net realized natural gas prices of 23%. The large decrease in natural gas prices in the 2010 period compared to the 2009 period was offset by a 21% increase in total production, 29% higher net realized crude oil prices and 23% higher net NGL prices in QEP Energy. During the year ended December 31, 2010, QEP Field Services gathering margins increased 23% and processing margins increased 29% from the year ended December 31, 2009.

A reconciliation of adjusted EBITDA to net income follows:

	Year Ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
			(in millions)		
Net income attributable to QEP Resources	**$ 267.2**	$ 326.2	$ 293.5	**$ (59.0)**	$ 32.7
Net income attributable to non-controlling interest	**3.2**	2.9	2.6	**0.3**	0.3
Net income	**270.4**	329.1	296.1	**(58.7)**	33.0
Discontinued operations, net of tax	**-**	(43.2)	(80.7)	**43.2**	37.5
Income from continuing operations	**270.4**	285.9	215.4	**(15.5)**	70.5
Unrealized gain on basis-only swaps	**(117.7)**	(121.7)	164.0	**4.0**	(285.7)
Net gain from asset sales	**(1.4)**	(12.1)	(1.5)	**10.7**	(10.6)
Interest and other loss (income)	**(4.1)**	(2.3)	(4.5)	**(1.8)**	2.2
Income taxes	**154.4**	167.0	117.6	**(12.6)**	49.4
Interest expense	**90.0**	84.4	70.1	**5.6**	14.3
Separation costs	**-**	13.5	-	**(13.5)**	13.5
Loss on early extinguishment of debt	**0.7**	13.3	-	**(12.6)**	13.3
Depreciation, depletion and amortization	**765.4**	643.4	559.1	**122.0**	84.3
Abandonment and impairment	**218.4**	46.1	20.3	**172.3**	25.8
Exploration expenses	**10.5**	23.0	25.0	**(12.5)**	(2.0)
Adjusted EBITDA	**$ 1,386.6**	$ 1,140.5	$ 1,165.5	**$ 246.1**	$ (25.0)

Revenue, Volumes and Prices

	Year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
			(in millions)		
Revenues					
Natural gas sales	**$ 1,239.1**	$ 1,205.3	$ 1,187.2	**$ 33.8**	$ 18.1
Oil sales	**324.2**	198.1	141.3	**126.1**	56.8
NGL sales	**129.7**	47.9	22.5	**81.8**	25.4
Gathering, processing and other	**380.9**	251.3	218.4	**129.6**	32.9
Purchased gas and oil sales	**1,085.3**	598.0	441.8	**487.3**	156.2
Total Revenues	**$ 3,159.2**	$ 2,300.6	$ 2,011.2	**$ 858.6**	$ 289.4

QEP Energy's revenues for the years ended December 31, 2011 and 2010, resulting from the sale of natural gas, oil and NGLs increased primarily due to increased production volumes and higher oil and NGL prices, offset by lower prices for natural gas, as follows:

	Year ended December 31, 2011			
	Natural Gas	Oil	NGLs	Total
	(in millions)			
QEP Energy Revenues				
2010 revenues	$ 1,205.3	$ 198.1	$ 47.9	$ 1,451.3
Changes associated with volumes [1]	193.2	50.7	58.1	302.0
Changes associated with prices [2]	(159.4)	75.4	23.7	(60.3)
2011 revenues	**$ 1,239.1**	**$ 324.2**	**$ 129.7**	**$ 1,693.0**

	Year ended December 31, 2010			
	Natural Gas	Oil	NGLs	Total
	(in millions)			
QEP Energy Revenues				
2009 revenues	$ 1,187.2	$ 141.3	$ 22.5	$ 1,351.0
Changes associated with volumes [1]	246.5	12.1	16.6	275.2
Changes associated with prices [2]	(228.4)	44.7	8.8	(174.9)
2010 revenues	$ 1,205.3	$ 198.1	$ 47.9	$ 1,451.3

[1] The revenue variance attributed to the change in volume is calculated by multiplying the change in volumes from the year ended December 31, 2011 or 2010, to the year ended December 31, 2010 or 2009, by the average realized price or fee for the year ended December 31, 2010 or 2009.
[2] The revenue variance attributed to the change in price is calculated by multiplying the change in realized prices or fee from the year ended December 31, 2011 or 2010, to the year ended December 31, 2010 or 2009, by volume for the year ended December 31, 2010 or 2009.

QEP Field Services revenues also increased for the years ended December 31, 2011 and 2010, as a result of higher volumes, improved processing and gathering fees in 2011 as compared to 2010, and higher gathering and processing volumes, and higher NGL prices and gathering fees in 2010 as compared to 2009, as follows:

	For the year ended December 31, 2011			
	NGLs	Processing	Gathering	Total
	(in millions)			
QEP Field Services				
2010 revenues	$ 94.8	$ 35.2	$ 189.2	$ 319.2
Changes associated with volumes [1]	39.3	2.3	7.8	49.4
Changes associated with fees [2]	45.9	18.4	32.6	96.9
2011 revenues	**$ 180.0**	**$ 55.9**	**$ 229.6**	**$ 465.5**

	For the year ended December 31, 2010			
	NGLs	Processing	Gathering	Total
	(in millions)			
QEP Field Services				
2009 revenues	$ 71.9	$ 32.6	$ 160.1	$ 264.6
Changes associated with volumes [1]	(1.0)	2.6	24.0	25.6
Changes associated with fees [2]	23.9	-	5.1	29.0
2010 revenues	$ 94.8	$ 35.2	$ 189.2	$ 319.2

[1] The revenue variance attributed to the change in volume is calculated by multiplying the change in volumes from the year ended December 31, 2011 or 2010, to the year ended December 31, 2010 or 2009, by the average realized price or fee for the year ended December 31, 2010 or 2009.
[2] The revenue variance attributed to the change in fees is calculated by multiplying the change in realized prices or fee from the year ended December 31, 2011 or 2010, to the year ended December 31, 2010 or 2009, by volume for the year ended December 31, 2010 or 2009.

Purchased gas and oil sales increased by $487.3 million, or 81% during the year ended December 31, 2011 from 2010. The increase in 2011 was primarily due to QEP Energy's additional revenues of $509.8 million related to gas purchases made in northwest Louisiana to utilize firm transportation capacity and the subsequent sale of those gas purchases. Purchased gas and oil sales increased $156.2 million, or 35%, during the year ended December 31, 2010 compared to 2009. The 2010 increase was the result of higher natural gas prices and increased sales volumes at QEP Marketing.

Reserves

QEP Energy's proved reserves in major operating areas at December 31, 2011 and 2010 are summarized below:

	2011		2010	
	(Bcfe)	**(% of total)**	(Bcfe)	(% of total)
Southern Region				
Haynesville/Cotton Valley	**782.9**	**22**	728.3	24
Midcontinent	**518.7**	**14**	442.2	15
Northern Region				
Pinedale Anticline	**1,531.0**	**42**	1,348.9	44
Uinta Basin	**393.6**	**11**	212.8	7
Rockies Legacy	**387.6**	**11**	298.5	10
Total QEP Energy	**3,613.8**	**100**	3,030.7	100

Production

QEP Energy reported production of 275.2 Bcfe during the year ended December 31, 2011 compared to 229.0 Bcfe and 189.5 Bcfe for the years ended December 31, 2010 and 2009, respectively. On an energy-equivalent basis, crude oil and NGL comprised approximately 14% of QEP Energy's total production for the year ended December 31, 2011, up from 11% for the years ended December 31, 2010 and 2009. A summary of production is shown in the following table:

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
QEP Energy production volumes					
Natural gas (Bcf)	**236.4**	203.8	168.7	**32.6**	35.1
Oil (Mbbl)	**3,741.3**	2,979.8	2,746.7	**761.5**	233.1
NGL (Mbbl)	**2,715.6**	1,225.8	705.0	**1,489.8**	520.8
Total production (Bcfe)	**275.2**	229.0	189.5	**46.2**	39.5
Average daily production (MMcfe)	**753.9**	627.4	519.1	**126.5**	108.3

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

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
QEP Energy - Natural gas (Bcf)					
Southern Region					
Haynesville/Cotton Valley	**107.1**	79.3	46.9	**27.8**	32.4
Midcontinent	**32.9**	30.8	32.7	**2.1**	(1.9)
Northern Region					
Pinedale Anticline	**69.3**	65.1	58.9	**4.2**	6.2
Uinta Basin	**14.9**	14.9	16.7	**-**	(1.8)
Rockies Legacy	**12.2**	13.7	13.5	**(1.5)**	0.2
Total production	**236.4**	203.8	168.7	**32.6**	35.1

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

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
QEP Energy - Oil (Mbbl)					
Southern Region					
Haynesville/Cotton Valley	**51.0**	78.4	121.1	**(27.4)**	(42.7)
Midcontinent	**835.3**	644.3	775.1	**191.0**	(130.8)
Northern Region					
Pinedale Anticline	**583.8**	551.8	486.9	**32.0**	64.9
Uinta Basin	**866.7**	957.1	930.7	**(90.4)**	26.4
Rockies Legacy	**1,404.5**	748.2	432.9	**656.3**	315.3
Total production	**3,741.3**	2,979.8	2,746.7	**761.5**	233.1

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

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
QEP Energy - NGL (Mbbl)					
Southern Region					
Haynesville/Cotton Valley	**8.4**	5.5	3.3	**2.9**	2.2
Midcontinent	**1,371.2**	997.0	456.1	**374.2**	540.9
Northern Region					
Pinedale Anticline	**1,099.6**	-	-	**1,099.6**	-
Uinta Basin	**106.4**	121.5	151.2	**(15.1)**	(29.7)
Rockies Legacy	**130.0**	101.8	94.4	**28.2**	7.4
Total production	**2,715.6**	1,225.8	705.0	**1,489.8**	520.8

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

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
QEP Energy - Total Production (Bcfe)					
Southern Region					
Haynesville/Cotton Valley	**107.5**	79.8	47.7	**27.7**	32.1
Midcontinent	**46.2**	40.6	40.1	**5.6**	0.5
Northern Region					
Pinedale Anticline	**79.4**	68.5	61.8	**10.9**	6.7
Uinta Basin	**20.8**	21.4	23.2	**(0.6)**	(1.8)
Rockies Legacy	**21.3**	18.7	16.7	**2.6**	2.0
Total production	**275.2**	229.0	189.5	**46.2**	39.5

Southern Region – Haynesville/Cotton Valley. Net production in the Haynesville/Cotton Valley area grew 35% to 107.5 Bcfe during the year ended December 31, 2011 compared to the year ended December 31, 2010 and represented 39% of the Company's total production. During the years ended December 31, 2010 and 2009, Haynesville/Cotton Valley production was 79.8 Bcfe and 47.7 Bcfe, respectively, which represented 35% and 25% of the Company's total production. Haynesville/Cotton Valley area production growth was driven by development drilling in the Haynesville Shale play in northwest Louisiana.

Southern Region – Midcontinent. Net production in the Midcontinent area grew 14% to 46.2 Bcfe during the year ended December 31, 2011 compared to the year ended December 31, 2010 and represented 17% of the Company's total production. During the years ended December 31, 2010 and 2009, Midcontinent area production was 40.6 Bcfe and 40.1 Bcfe, respectively, which represented 18% and 21% of the Company's total production. Midcontinent area production growth was driven by continued development of the Granite Wash/Atoka Wash play in the Texas Panhandle and the Woodford "Cana" Shale horizontal gas play in the Anadarko Basin of western Oklahoma.

Northern Region – Pinedale Anticline. Net production from the Pinedale Anticline in western Wyoming grew 16% to 79.4 Bcfe during the year ended December 31, 2011 compared to the year ended December 31, 2010 and represented 29% of the Company's total production. During the years ended December 31, 2010 and 2009, Pinedale Anticline production was 68.5 Bcfe and 61.8 Bcfe, respectively, which represented 30% and 33% of the Company's total production. As a result of a new fee-based processing agreement between QEP Energy and QEP Field Services at Blacks Fork II, NGL production at Pinedale for the second half of 2011 was 1,099.6 Mbbl, contrasted with no reportable NGL production in the comparable 2010 and 2009 periods.

Northern Region – Uinta Basin. In the Uinta Basin, production decreased 3% during the year ended December 31, 2011, due to decreased drilling activity, despite a first quarter 2011 prior-period adjustment of QEP's ownership interest within a federal unit, which resulted in a positive adjustment to reported volumes of 1.6 Bcfe. During the year ended December 31, 2010, Uinta production was 1.8 Bcfe lower than in 2009 due to decreased drilling activity resulting from low natural gas prices.

Northern Region – Rockies Legacy. Rockies Legacy net production in 2011 increased by 14% to 21.3 Bcfe. Rockies Legacy production in 2010 was 2.0 Bcfe higher than in 2009. Increases in both 2011 and 2010 were due to increased oil directed drilling activity in the North Dakota Bakken/Three Forks play. Most of QEP's wells in North Dakota have been connected to oil gathering lines during 2011, thereby eliminating future weather-related oil sales interruptions. QEP Energy Rockies Legacy properties include all Northern Region properties except the Pinedale Anticline and the Uinta Basin.

Pricing

During the year ended December 31, 2011, QEP revised its reporting of transportation and handling costs. Transportation and handling costs have been recast on the Consolidated Income Statement from revenues to "Natural gas, oil and NGL transportation and other handling costs" for all periods presented. See Note 1 "Summary of Significant Accounting Policies," in Item 8, Part II of this Annual Report on Form 10-K, for additional information. Field-level and realized prices (after the impact of all settled commodity derivatives) for natural gas at QEP Energy were lower during the year ended December 31, 2011 than in the 2010 and 2009 comparable periods, while 2011 realized oil and NGL prices were higher than in 2010 and 2009. A regional comparison of QEP Energy's average field-level prices are shown in the following tables:

	Year Ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
QEP Energy - Average field-level natural gas price (per Mcf)					
Southern Region	**$ 4.00**	$ 4.24	$ 3.69	**$ (0.24)**	$ 0.55
Northern Region	**3.87**	4.11	3.30	**(0.24)**	0.81
Average field-level natural gas price	**3.95**	4.18	3.48	**(0.23)**	0.70

	Year Ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
QEP Energy - Average field-level oil price (per bbl)					
Southern Region	**$ 90.45**	$ 74.93	$ 54.41	**$ 15.52**	$ 20.52
Northern Region	**84.88**	67.62	49.17	**17.26**	18.45
Average field-level oil price	**86.20**	69.39	50.88	**16.81**	18.51

	Year Ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
QEP Energy - Average field-level NGL price (per bbl)					
Southern Region	**$ 43.66**	$ 35.57	$ 27.15	**$ 8.09**	$ 8.42
Northern Region	**52.00**	54.62	40.56	**(2.62)**	14.06
Average field-level NGL price	**47.76**	39.04	31.82	**8.72**	7.22

A comparison of net realized average natural gas, oil and NGL prices, including the realized losses on basis-only swaps, which did not qualify for hedge accounting and are therefore not included in revenue, are shown in the following table.

	Year Ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
Natural gas (per Mcf)					
Average field-level natural gas price	**$ 3.95**	$ 4.18	$ 3.48	**$ (0.23)**	$ 0.70
Natural gas commodity derivative impact	**1.29**	1.74	3.56	**(0.45)**	(1.82)
Average revenue [(1)]	**5.24**	5.92	7.04	**(0.68)**	(1.12)
Realized losses on basis-only swaps [(2)]	**(0.50)**	(0.60)	(0.16)	**0.10**	(0.44)
Net realized natural gas price	**$ 4.74**	$ 5.32	$ 6.88	**$ (0.58)**	$ (1.56)
Oil (per bbl)					
Average field-level oil price	**$ 86.20**	$ 69.39	$ 50.88	**$ 16.81**	$ 18.51
Oil commodity derivative impact	**0.43**	(2.91)	0.58	**3.34**	(3.49)
Net realized oil price	**$ 86.63**	$ 66.48	$ 51.46	**$ 20.15**	$ 15.02
NGL (per bbl)					
Average field-level NGL price	**$ 47.76**	$ 39.04	$ 31.82	**$ 8.72**	$ 7.22

(1) Reported in revenues in the consolidated income statement.
(2) Reported below operating income in the consolidated income statement.

Commodity Derivatives Impact

The Company enters into commodity derivative instruments to manage its exposure to price fluctuations on a portion of its forecasted natural gas and oil production. The impact of QEP's commodity derivatives transactions on the Company's financial statements for the years ended December 31, 2011, 2010 and 2009, is presented below. The net effect of the portion of natural gas basis-only swaps that do not qualify for hedge accounting is reported in the Consolidated Statements of Income below operating income. Derivative positions as of December 31, 2011 and 2010, are summarized in Note 6 to the consolidated financial statements in Item 8 of this Annual Report on Form 10-K.

	Year Ended December 31,		
	2011	2010	2009
Volumes subject to commodity derivatives as a percent of gas production - QEP Energy			
Fixed price swaps	**50%**	74%	77%
Costless collars	**12%**	3%	-
Basis-only swaps	-	-	15%
Volumes subject to commodity derivatives as a percent of oil production - QEP Energy			
Fixed price swaps	**3%**	31%	42%
Costless collars	**29%**	24%	-
Volumes subject to commodity derivatives as a percent of propane production - QEP Field Services			
Fixed price swaps	**23%**	-	-

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
			(in millions)		
Impact of settled commodity derivatives on financial statements					
Natural gas sales	**$ 305.5**	$ 353.8	$ 599.3	**$ (48.3)**	$ (245.5)
Oil sales	**1.6**	(8.7)	1.6	**10.3**	(10.3)
Gathering, processing and other	**(0.2)**	-	-	**(0.2)**	-
Purchased gas and oil sales	-	-	27.8	-	(27.8)
Purchased gas and oil expense	**4.3**	3.1	(9.2)	**1.2**	12.3
Loss (gain) recognized in income for the ineffective portion of hedges					
Interest and other income	**0.1**	0.2	(0.1)	**(0.1)**	0.3
Impact of settled commodity derivatives that do not qualify for hedge accounting					
Unrealized gain (loss) on basis-only swaps	**117.7**	121.7	(164.0)	**(4.0)**	285.7
Realized (loss) on basis-only swaps	**(117.7)**	(121.7)	(25.6)	**4.0**	(96.1)

The change in unrealized gains and losses on natural gas basis-only swaps increased 2011 net income $75.2 million and increased 2010 net income by $76.3 million. During 2009, the change in unrealized gains and losses on natural gas basis-only swaps decreased net income by $103.3 million. As of December 31, 2009, all of the Company's basis-only swaps had been paired with NYMEX gas fixed-price swaps or price-collars and re-designated as cash flow hedges. Changes in the fair value of these derivative instruments subsequent to their re-designation were recorded in Accumulated Other Comprehensive Income (AOCI), however, changes in the fair value of these derivative instruments occurring prior to their re-designation were recorded in the Consolidated Statement of Income.

Gathering

QEP Field Services posted a 22% increase in gathering margin during the year ended December 31, 2011, primarily due to an increase in the NGL value received from a short-term, third-party processing arrangement for certain volumes in the Northern Region and a 3% increase in the average gathering rate. During the year ended December 31, 2010, gathering margin increased by $28.1 million due to the transfer of the northwest Louisiana gathering system assets from QEP Energy to QEP Field Services, which increased system throughput volume along with increased drilling activity in the Haynesville/Cotton Valley and Pinedale Anticline plays. Gathering system throughput volume was 1.4 million MMBtu per day for the year ended December 31, 2011, up from the 1.3 million MMBtu per day and 1.1 million MMBtu per day during the years ended December 31, 2010 and 2009. The increased volumes in 2011 and 2010 were mainly related to the northwest Louisiana gathering system, as described above, which accounted for 21%, and 16% of the total throughput during the years ended December 31, 2011, and 2010, respectively.

During the year ended December 31, 2011, QEP contracted for 200 million cubic feet per day of gas to a third-party cryogenic processing plant on an interruptible basis, reported in QEP Field Services as "Other gathering revenues." QEP expects "Other gathering revenues" to diminish and to be replaced by keep-whole processing revenues in QEP Field Services and NGL revenues in QEP Energy.

Following is a summary of QEP Field Services' financial and operating results from gathering activities:

	Year Ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
Gathering Margin					
Gathering revenues	**$ 161.1**	$ 152.5	$ 127.3	**$ 8.6**	$ 25.2
Other gathering revenues	**68.5**	36.7	32.8	**31.8**	3.9
Gathering expense	**(44.6)**	(37.6)	(36.6)	**(7.0)**	(1.0)
Gathering margin	**$ 185.0**	$ 151.6	$ 123.5	**$ 33.4**	$ 28.1
Operating Statistics					
Natural gas gathering volumes (in millions of MMBtu)					
For unaffiliated customers	**261.2**	276.8	301.2	**(15.6)**	(24.4)
For affiliated customers	**234.2**	198.9	112.6	**35.3**	86.3
Total Gas Gathering Volumes	**495.4**	475.7	413.8	**19.7**	61.9
Average gas gathering revenue (per MMBtu)	**$ 0.33**	$ 0.32	$ 0.31	**$ 0.01**	$ 0.01

Processing

Although a significant portion of the QEP Field Services gas processing services are performed for a volumetric-based fee, a portion of its gas processing agreements result in commodity price exposure. Such agreements are referred to as "keep-whole" processing agreements, whereby the Company has the right to extract NGL recovered at its processing plants and the obligation to replace the Btu equivalent value of such NGL with dry natural gas (the "shrink"). Under these agreements, the Company is exposed to the spread between NGL prices and natural gas prices.

Processing margin increased 93% during the year ended December 31, 2011 compared to the year ended December 31, 2010, due to increased keep-whole processing margins and fee-based processing volumes and lower natural gas prices. The increased keep-whole processing margin was mostly the result of increased NGL prices and volume. NGL prices increased 34% and NGL volumes increased 42% during the year ended December 31, 2011. Fee-based processing revenues increased 53% during the year ended December 31, 2011 compared to 2010, due to an 6% increase in fee-based processing volumes to 240.7 million MMBtu and a 38% increase in the processing fee rate. The increased processing volume 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.

Approximately 70%, 78% and 82% of QEP Field Services' net operating revenue was derived from fee-based gathering and processing agreements during the years ended December 31, 2011, 2010 and 2009. The decline in the relative percentage of fee-based revenues was due primarily to the increase in keep-whole processing margins in 2011. Processing margin increased in 2010 compared with 2009 by $19.4 million due to improved NGL prices and lower natural gas costs. The 16.2 million MMBtu increase in fee-based processing volumes in 2010 was driven by increased throughput at QEP Field Services' Stagecoach plant in eastern Utah.

Frac spread, as used in the following table, is defined as the difference between the market value for 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 and the related transportation and handling costs. Following is a summary of QEP Field Services' processing financial and operating results:

	Year Ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
Processing Margin					
NGL sales	**$ 180.0**	$ 94.8	$ 71.9	**$ 85.2**	$ 22.9
Processing (fee-based) revenues	**53.7**	35.2	32.4	**18.5**	2.8
Other processing fees	**2.2**	-	0.2	**2.2**	(0.2)
Processing (expense)	**(12.2)**	(11.9)	(10.3)	**(0.3)**	(1.6)
Processing plant fuel and shrinkage (expense)	**(49.2)**	(32.6)	(28.1)	**(16.6)**	(4.5)
Natural gas, oil and NGL transportation and other handling costs	**(9.3)**	-	-	**(9.3)**	-
Processing margin	**$ 165.2**	$ 85.5	$ 66.1	**$ 79.7**	$ 19.4
Frac spread (NGL sales less processing plant fuel and shrinkage less natural gas, oil and NGL transportation and other handling costs)	**$ 121.5**	$ 62.2	$ 43.8	**$ 59.3**	$ 18.4
Operating Statistics					
Natural gas processing volumes					
NGL sales (MMgal)	**141.8**	100.2	101.6	**41.6**	(1.4)
Average NGL sales price (per gal)	**$ 1.27**	$ 0.95	$ 0.71	**$ 0.32**	$ 0.24
Fee-based processing volumes (in millions of MMBtu)					
For unaffiliated customers	**122.9**	116.8	110.6	**6.1**	6.2
For affiliated customers	**117.8**	109.4	99.4	**8.4**	10.0
Total fee-based processing volumes	**240.7**	226.2	210.0	**14.5**	16.2
Average fee-based processing revenue (per MMBtu)	**$ 0.22**	$ 0.16	$ 0.15	**$ 0.06**	$ 0.01

Operating Expenses

The following table presents QEP's total operating expenses and the changes from previous reporting periods for the years ended December 31, 2011, 2010 and 2009. The narrative following the below table explains the significant variances between the comparable periods.

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
			(in millions)		
Purchased gas and oil expense	**$ 1,077.1**	$ 589.3	$ 427.8	**$ 487.8**	$ 161.5
Lease operating expense	**145.2**	125.0	125.5	**20.2**	(0.5)
Natural gas, oil and NGL transportation and other handling costs	**102.2**	54.2	38.7	**48.0**	15.5
Gathering, processing and other	**107.3**	83.2	76.2	**24.1**	7.0
General and administrative	**123.2**	107.2	91.7	**16.0**	15.5
Separation costs	-	13.5	-	**(13.5)**	13.5
Production and property taxes	**105.4**	82.5	62.9	**22.9**	19.6
Depreciation, depletion and amortization	**765.4**	643.4	559.1	**122.0**	84.3
Exploration expenses	**10.5**	23.0	25.0	**(12.5)**	(2.0)
Abandonment and impairment	**218.4**	46.1	20.3	**172.3**	25.8
Total operating expenses	**$ 2,654.7**	$ 1,767.4	$ 1,427.2	**$ 887.3**	$ 340.2

Purchased gas and oil expense increased in 2011 due to increased purchased gas expense at QEP Energy of $506.4 million. The increased purchased gas expense at QEP Energy relates to gas purchases made in northwest Louisiana to utilize firm transportation capacity. Purchased gas and oil expense increased $161.5 million during the year ended December 31, 2010 compared to the year ended December 31, 2009, due to higher oil and NGL prices and increased volumes.

Lease operating expense increased $20.2 million, or 16% to $145.2 million, during 2011 compared to 2010, driven by a 20% increase in production of natural gas and oil and NGL equivalents during the period. Lease operating expense during 2010 compared to 2009 was essentially flat, despite an increase in production due to the increase in Haynesville and Pinedale volumes, which have lower lease operating expenses.

Natural gas, oil and NGL transportation and other handling costs increased $48.0 million, due primarily to processing costs associated with increased NGL production and related transportation costs under a revised processing agreement at Pinedale. Natural gas, oil and NGL transportation and other handling costs increased $15.5 million in 2010 compared to 2009, due primarily to increased natural gas production and related transportation costs at Haynesville/Cotton Valley area. See Item 8, Note 1 “Summary of Significant Accounting Policies,” for a discussion of the recasting of transportation and other handling costs.

Gathering, processing and other expense increased by $24.1 million due to higher gathering and processing volumes in 2011 when compared to the 2010 period. Gathering, processing and other expense increased by $7.0 million during the year ended December 31, 2010, compared to the year ended December 31, 2009 also due to higher gathering and processing volumes.

Total QEP general and administrative (G&A) expense increased to $123.2 million for the year ended December 31, 2011, compared with $107.2 million for the year ended December 31, 2010. The increase in 2011 resulted from an increase in the number of employees, increased employee benefit plan and stock-based compensation related expenses, increased legal and outside professional services and higher insurance costs. QEP total G&A expense increased by $15.5 million, or 17%, during the year ended December 31, 2010 compared to 2009. The 2010 increases primarily related to higher labor, benefits and stock-based compensation expenses.

During the year ended December 31, 2010, QEP reported separation costs of $13.5 million, respectively, related to the Spin-off of QEP Resources, Inc. from Questar Corporation on June 30, 2010. The expenses consisted primarily of QEP’s share of certain fees and expenses for financial, legal and tax advisory services and for severance expenses for terminated employees. There were no separation costs in the years ended December 31, 2011 and 2009.

Higher natural gas, oil and NGL production and higher field-level oil and NGL prices, resulted in higher total production and property taxes during the year ended December 31, 2011, partially offset by lower field-level sales prices for natural gas during the same period. Production and property taxes were higher during the year ended December 31, 2010 compared to 2009 as the result of higher field-level natural gas and oil sales prices.

QEP’s total depreciation, depletion and amortization expense grew $122.0 million, or 19%, in 2011 from the 2010 comparable period, as a result of increased production at QEP Energy combined with plant additions at QEP Field Services. During the year ended December 31, 2010, QEP’s total depreciation, depletion and amortization expense increased to $643.4 million from the $559.1 million during the year ended December 31, 2009, due to increased capital spending at both QEP Energy and QEP Field Services and increased production at QEP Energy.

Exploration expenses were $10.5 million in 2011 compared to $23.0 million in 2010, due to a decrease in dry hole costs of $9.3 million and reduced seismic acquisition costs of $2.5 million. During the year ended December 31, 2010, exploration expenses decreased by $2.0 million, or 8%, despite an $8.7 million charge associated with an unsuccessful exploratory well drilled on the Borie Niobrara prospect in southeastern Wyoming. The overall decrease in 2010 was due to lower geological, geophysical and other exploratory expenses in 2010 compared to 2009.

Abandonment and impairment expenses increased to $218.4 million during the year ended December 31, 2011 compared with $46.1 million during the 2010 period. As discussed earlier, the increase was primarily due to the recognition of a non-cash price-related impairment charge of $195.2 million in the fourth quarter of 2011 on some of the Company’s mature, dry gas, and higher cost properties in both the Northern and Southern Regions. The impairment charge related to the reduced value of these areas resulting from lower natural gas prices and the current forward curve for natural gas prices. The assets were written down to their estimated fair value. During the year ended December 31, 2010, abandonment and impairment expenses increased by $25.8 million from the 2009 period, due to higher impairment costs associated with the Company’s unproven acreage, which QEP amortizes on a straight-line basis over the primary term of the lease.

CONSOLIDATED RESULTS BELOW OPERATING INCOME

Interest and other income

Interest and other income are comprised primarily of interest earned on investments, gains and losses on warehouse inventory, hedge ineffectiveness and other miscellaneous income. During the year ended December 31, 2011, interest and other income increased by $1.8 million, primarily due to the variance in inventory valuations, offset by lower gains on warehouse inventory sales. Interest and other income decreased $2.2 million in 2010 compared with 2009 due primarily to a valuation adjustment on pipe inventory.

Loss from early extinguishment of debt

The loss from early extinguishment of debt was $0.7 million during the year ended December 31, 2011 compared to $13.3 million in the 2010 period. The loss of $0.7 million in 2011 related to replacing the previous $1.0 billion revolving credit facility with a new $1.5 billion revolving credit facility in the third quarter of 2011. The loss of $13.3 million during 2010 was the result of the purchase of $638.0 million principal amount of senior notes and the termination of a $500 million term loan related to the Spin-off from Questar both occurring in the third quarter of 2010.

Realized and unrealized gain (loss) on basis-only swaps

In the past, the Company has used basis-only swaps to manage the risk of widening basis differentials. Basis-only swaps do not qualify for hedge accounting. As of December 31, 2009, all of the Company's basis-only swaps had been paired with fixed-price swaps and re-designated as cash flow hedges. Fair value changes occurring prior to re-designation were recorded in the Consolidated Statements of Income. Changes in the fair value of the derivative instruments subsequent to the re-designation were recorded in Accumulated Other Comprehensive Income. Realized losses on settlements of basis-only swaps relating to the period prior to re-designation amounted to $117.7 million, $121.7 million and $25.6 million during the years ended December 31, 2011, 2010 and 2009, respectively. Unrealized gains on basis-only swaps amounted to $117.7 million and $121.7 million during the years ended December 31, 2011, and 2010, respectively. Conversely, during the year ended December 31, 2009, QEP reported an unrealized loss on basis-only swaps of $164.0 million.

Interest expense

Interest expense increased 7% to $90.0 million in 2011 compared to 2010 due to December 31, 2011 average debt levels that were approximately $165 million higher than average debt levels in the comparable prior period. During the year ended December 31, 2010, interest expense increased to $84.4 million from $70.1 million in 2009, primarily due to financing activities associated with the issuance of new bonds in 2010 and higher debt levels.

Income taxes

The effective combined federal and state income tax rate was 36.3% for the year ended December 31, 2011, slightly lower than the 36.9% in 2010, but higher than the 35.3% in 2009. The decrease in the combined rate during 2011 was primarily due to the Spin-off which increased the 2010 rate. The 2010 increase in the combined rate was primarily due to a lower state income tax rate in 2009.

DISCUSSION BY LINE OF BUSINESS

QEP Energy

QEP Energy reported net income of $104.7 million in the year ended December 31, 2011, a decrease of 49% from $203.9 million in 2010. As discussed earlier, the primary reason for the decrease was the recognition of a non-cash price-related impairment charge of $195.2 million in the fourth quarter of 2011 on some of QEP Energy's mature, dry gas, and higher cost properties in both the Northern and Southern Regions. The impairment charge related to the reduced value of these areas resulting from lower natural gas prices and the current forward curve for natural gas prices. QEP Energy net income also decreased as a result of the continual decline in net realized natural gas prices, which decreased 11% to $4.74 per Mcf in 2011, compared to $5.32 per Mcf in 2010. These natural gas price-related negative impacts were partially offset by a 20% increase in natural gas-equivalent total production and a 30% increase in net realized oil prices in 2011. Net realized oil prices were $86.63 per bbl in 2011 up from $66.48 in 2010. QEP Energy's net income for the year ended December 31, 2010 was $203.9 million, $69.0 million higher than 2009. The 2010 increase over 2009 was due to higher production of 229.0 Bcfe and higher net realized crude oil and NGL prices in 2010, partially offset by lower net realized natural gas prices. Changes in unrealized basis-only swaps increased net income $75.2 million and $76.3 million during the years ended December 31, 2011, and 2010, respectively, compared to decreasing net income by $103.3 million in 2009. Following is a summary of QEP Energy's financial and operating results:

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	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
			(in millions)		
Operating Income					
Revenues					
Natural gas sales	**$ 1,239.1**	$ 1,205.3	$ 1,187.2	**$ 33.8**	$ 18.1
Oil sales	**324.2**	198.1	141.3	**126.1**	56.8
NGL sales	**129.7**	47.9	22.5	**81.8**	25.4
Purchased gas sales	**509.8**	-	-	**509.8**	-
Other	**10.4**	5.0	5.0	**5.4**	-
Total Revenues	**2,213.2**	1,456.3	1,356.0	**756.9**	100.3
Operating expenses					
Purchased gas expense	**506.4**	-	-	**506.4**	-
Lease operating expense	**148.2**	127.3	127.5	**20.9**	(0.2)
Natural gas, oil and NGL transportation and other handling costs	**186.0**	125.5	88.7	**60.5**	36.8
General and administrative	**98.4**	78.0	68.0	**20.4**	10.0
Production and property taxes	**99.1**	77.8	58.3	**21.3**	19.5
Depreciation, depletion and amortization	**707.2**	592.5	512.8	**114.7**	79.7
Exploration expenses	**10.5**	23.0	25.0	**(12.5)**	(2.0)
Abandonment and impairment	**218.4**	46.1	20.3	**172.3**	25.8
Total Operating Expenses	**1,974.2**	1,070.2	900.6	**904.0**	169.6
Net gain from asset sales	**1.4**	13.7	1.6	**(12.3)**	12.1
Operating Income	**240.4**	399.8	457.0	**(159.4)**	(57.2)
Interest and other income (loss)	**4.0**	2.1	3.9	**1.9**	(1.8)
Income from unconsolidated affiliates	**0.1**	0.2	0.1	**(0.1)**	0.1
Unrealized and realized gain (loss) on basis-only swaps	**-**	-	(189.6)	**-**	189.6
Interest expense	**(81.9)**	(78.5)	(63.9)	**(3.4)**	(14.6)
Income from Continuing Operations before Income Taxes	**162.6**	323.6	207.5	**(161.0)**	116.1
Income taxes	**(57.9)**	(119.7)	(72.6)	**61.8**	(47.1)
Net Income Attributable to QEP	**$ 104.7**	$ 203.9	$ 134.9	**$ (99.2)**	$ 69.0

Operating expenses per unit

The following table presents certain QEP Energy operating expenses on a per unit of production basis. QEP Energy total operating expenses (the sum of depreciation, depletion and amortization expense, lease operating expense, natural gas, oil and NGL transportation and other handling costs, general and administrative expense, and a portion of total QEP interest expense that is allocated to QEP Energy based on intercompany agreements and production taxes) per Mcfe of production increased 2% to $4.81 per Mcfe in 2011 versus $4.72 per Mcfe in 2010. For the year ended December 31, 2010, QEP Energy total operating costs per Mcfe decreased $0.14 per Mcfe, or 3% from 2009. Operating expenses per unit are summarized in the following table:

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
			(per Mcfe)		
Depreciation, depletion and amortization	**$ 2.57**	$ 2.59	$ 2.71	**$ (0.02)**	$ (0.12)
Lease operating expense	**0.54**	0.56	0.67	**(0.02)**	(0.11)
Natural gas, oil and NGL transportation and other handling costs	**0.68**	0.55	0.47	**0.13**	0.08
General and administrative expense	**0.36**	0.34	0.36	**0.02**	(0.02)
Allocated interest expense	**0.30**	0.34	0.34	**(0.04)**	-
Production taxes	**0.36**	0.34	0.31	**0.02**	0.03
Total Operating Expenses	**$ 4.81**	$ 4.72	$ 4.86	**$ 0.09**	$ (0.14)

Depreciation, depletion and amortization (DD&A) expense per Mcfe decreased $0.02 in the year ended December 31, 2011 from the 2010 period. QEP Energy's DD&A expense increased $114.7 million during the year ended December 31, 2011 from the year ended December 31, 2010. While QEP Energy's total DD&A increased in 2011, the lower per unit expense in 2011 was the result of booking NGL reserves associated with the fee-based processing agreement entered into between QEP Energy and QEP Field Services for QEP's Pinedale production. In 2010, DD&A expense decreased by $0.12 per Mcfe compared to 2009 primarily as a result of increased proved reserves related to higher field-level natural gas and oil prices compared to the prior year.

Lease operating expense per Mcfe decreased $0.02 for the year ended December 31, 2011 from the 2010 period as the result of increased production volumes in lower cost areas. Growing production from new high-rate, low-operating cost wells in the Haynesville/Cotton Valley area and in the Pinedale Anticline, coupled with declining production from older higher cost areas, reduced average per Mcfe lease operating expense. Lease operating expense per Mcfe was 16% lower in 2010 compared to 2009, primarily due to higher production volumes combined with flat operating expenses.

QEP Energy's average production costs (lease operating expense) per Mcfe were 4% lower in the 2011 period compared to the 2010 period. The decrease was a result of growing production in lower cost operating areas such as Haynesville/Cotton Valley and Pinedale, coupled with declining production in higher cost areas, which more than offset the higher cost associated with operating the growing oil volumes in the Northern Region. QEP Energy's average production cost decreased $0.11 per Mcfe in 2010 due to higher production volumes and flat operating expenses. The following table presents average production cost, excluding production taxes for QEP Energy for QEP Energy by region on a per unit of production basis.

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
			(per Mcfe)		
Southern Region	**$ 0.50**	$ 0.55	$ 0.79	**$ (0.05)**	$ (0.24)
Northern Region	**0.58**	0.56	0.57	**0.02**	(0.01)
Average production cost	**0.54**	0.56	0.67	**(0.02)**	(0.11)

Natural gas, oil and NGL transportation and other handling costs per Mcfe were 24% higher in 2011 than in 2010, due primarily to processing costs associated with increased NGL production and related transportation costs under a revised processing agreement at Pinedale. Natural gas, oil and NGL transportation and other handling costs increased $0.08 per Mcfe in 2010 compared to 2009, due primarily to increased natural gas production and related transportation costs at the Haynesville/Cotton Valley area. See Note 1 to the consolidated financial statements, "Summary of Significant Accounting Policies," for a discussion of the recasting of transportation and other handling costs.

General and administrative (G&A) expense per Mcfe increased $0.02 per Mcfe during the year ended December 31, 2011, as the result of higher G&A expenses, which were primarily related to employee benefit plan and stock-based compensation related expenses, increased legal and outside professional services and higher insurance costs, which were partially offset by increased production in 2011. G&A expenses per Mcfe were 6% lower in 2010 than 2009 as a result of increased production volumes partially offset by higher labor, benefits and stock-based compensation expenses in 2010.

Allocated interest expense per unit of production decreased $0.04 per Mcfe in the year ended December 31, 2011, primarily due to higher production volumes. Allocated interest expense per Mcfe of production was flat when comparing the year ended December 31, 2010 to 2009.

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. Accordingly, production taxes per Mcfe increased by $0.02 per Mcfe during the year ended December 31, 2011 because of higher field-level oil and NGL prices. In the 2010 period, production taxes increased by 10% over the 2009 period, as the result of higher natural gas, oil and NGL prices.

QEP Field Services

QEP Field Services, which provides gas gathering and processing services, generated net income of $154.5 million in the year ended December 31, 2011 compared to $91.1 million in 2010, a 70% increase. During the year ended December 31, 2010, net income increased $21.7 million from the $69.4 million in 2009. The increase in net income in both 2011 and 2010 was the result of higher gathering and processing margins and increased throughput volumes. Following is a summary of QEP Field Services' financial and operating results:

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
			(in millions)		
Operating Income					
Revenues					
NGL sales	**$ 180.0**	$ 94.8	$ 71.9	**$ 85.2**	$ 22.9
Processing (fee based)	**53.7**	35.2	32.4	**18.5**	2.8
Other processing fees	**2.2**	-	0.2	**2.2**	(0.2)
Gathering	**161.1**	152.5	127.3	**8.6**	25.2
Other gathering	**68.5**	36.7	32.8	**31.8**	3.9
Total Revenues	**465.5**	319.2	264.6	**146.3**	54.6
Operating expenses					
Processing	**12.2**	11.9	10.3	**0.3**	1.6
Processing plant fuel and shrinkage	**49.2**	32.6	28.1	**16.6**	4.5
Gathering	**44.6**	37.6	36.6	**7.0**	1.0
Natural gas, oil and NGL transportation and other handling costs	**9.3**	-	-	**9.3**	-
General and administrative	**29.2**	31.6	25.0	**(2.4)**	6.6
Taxes other than income taxes	**6.1**	4.4	4.6	**1.7**	(0.2)
Depreciation, depletion and amortization	**55.7**	48.9	44.3	**6.8**	4.6
Total Operating Expenses	**206.3**	167.0	148.9	**39.3**	18.1
Net gain (loss) from asset sales	**-**	(1.6)	(0.1)	**1.6**	(1.5)
Operating Income	**259.2**	150.6	115.6	**108.6**	35.0
Interest and other income	**0.1**	0.1	(0.2)	**-**	0.3
Income from unconsolidated affiliates	**5.4**	2.8	2.6	**2.6**	0.2
Interest expense	**(13.6)**	(7.6)	(6.0)	**(6.0)**	(1.6)
Income from Continuing Operations before Income Taxes	**251.1**	145.9	112.0	**105.2**	33.9
Income taxes	**(93.4)**	(51.9)	(40.0)	**(41.5)**	(11.9)
Income from Continuing Operations	**157.7**	94.0	72.0	**63.7**	22.0
Net income attributable to noncontrolling interest	**(3.2)**	(2.9)	(2.6)	**(0.3)**	(0.3)
Net Income Attributable to QEP	**$ 154.5**	$ 91.1	$ 69.4	**$ 63.4**	$ 21.7

See "Gathering" and "Processing" sections, as appeared earlier, for a discussion of the changes in QEP Field Services comparative financial statements.

QEP Marketing

QEP Marketing, which markets affiliate and third-party natural gas and oil, and owns and operates a gas storage facility, generated net income from continuing operations of $8.4 million during 2011, compared with $6.7 million during 2010. The increase in 2011 was due to a $2.7 million increase in interest income and a 54% increase in marketing sales volumes, partially offset by a 5% decrease in marketing margins. QEP Marketing net income decreased 21% from the 2009 net income of $8.5 million. The 2010 decrease from 2009 was a result of lower marketing and storage margins due to an overall decrease in natural gas price volatility.

LIQUIDITY AND CAPITAL RESOURCES

QEP funds its operations, capital expenditures and working capital requirements with cash flow from its operating activities, borrowings under its credit facility and, periodically, proceeds from debt offerings and asset sales. The Company believes cash flow from operations and availability under its credit facility will be sufficient to fund the Company's planned capital expenditures and operating expenses for 2012. To the extent actual operating results differ from the Company's estimates, the Company's liquidity could be adversely affected.

Cash Flows from Operating Activities

Cash flows from operations are primarily affected by natural 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. However, in general, QEP plans to hedge approximately 50% of its forecasted production by the end of the first quarter of the current year. See "Commodity Derivative Impact" above.

Net cash provided by operating activities of continuing operations increased 30% in 2011 compared to 2010, due to higher noncash adjustments to net income and a lower use of cash from operating assets and liabilities in 2011 compared with the use of cash in the 2010 period. Noncash adjustments to net income consisted primarily of depreciation, depletion and amortization; noncash unrealized gains and losses on basis-only swaps; changes in deferred income taxes; and abandonment and impairment charges. Cash uses from operating assets and liabilities were higher in 2011 primarily due to increases in accounts receivable and inventories during 2011 compared to 2010. Net cash provided by continuing operating activities from continuing operations decreased in 2010 by $151.9 million from 2009. Cash sources from operating assets and liabilities were lower in 2010 primarily due to reductions in accounts receivable during 2009 and a decrease in current federal income taxes payable due to bonus depreciation. Net cash provided from continuing operating activities is presented below:

	Year Ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
		(in millions)			
Income from continuing operations	**$ 270.4**	$ 285.9	$ 215.4	$ (15.5)	$ 70.5
Noncash adjustments to net income	**1,050.9**	784.5	863.0	266.4	(78.5)
Changes in operating assets and liabilities	**(28.7)**	(72.9)	71.0	44.2	(143.9)
Net cash provided by operating activities of continuing operations	**$ 1,292.6**	$ 997.5	$ 1,149.4	$ 295.1	$ (151.9)

Cash Flows from Investing Activities

A comparison of capital expenditures for continuing operations during the years ended December 31, 2011, 2010 and 2009 and a forecast for calendar year 2012 are presented in the table below:

	Year Ended December 31,			
	2011	2010	2009	2012 Forecast
		(in millions)		
QEP Energy	**$ 1,338.8**	$ 1,215.8	$ 1,033.7	$ 1,280.0
QEP Field Services	**101.6**	268.2	71.8	170.0
QEP Marketing and other	**5.4**	1.9	1.4	-
Total accrued capital expenditures of continuing operations	**1,445.8**	1,485.9	1,106.9	1,450.0
Change in accruals	**(14.7)**	(16.9)	90.0	-
Total cash capital expenditures of continuing operations	**$ 1,431.1**	$ 1,469.0	$ 1,196.9	$ 1,450.0

QEP Energy capital investment during the year ended December 31, 2011 increased $126.1 million over the 2010 period due to an increase in the number of company-operated well completions as a result of ongoing efficiency gains, combined with acquisition of additional working interests in certain wells due to partner elections not to participate. QEP Energy capital expenditures were higher in 2010 compared to 2009 due to an increased drilling program in 2010.

QEP Field Services capital investment declined $166.6 million during the year ended December 31, 2011 compared to the 2010 period due to the completion of major capital projects in eastern Utah and northwest Louisiana in late 2010 and the completion of the Blacks Fork II plant early in the third quarter of 2011. QEP Field Services capital investment was higher in 2010 than 2009 due to increased investment in its gathering, processing and treating facilities to expand capacity in western Wyoming, eastern Utah and northwest Louisiana.

Cash Flows from Financing Activities

During the year ended December 31, 2011, net cash used in investing activities of $1,422.9 million exceeded net cash provided by operating activities of $1,292.6 million by $130.3 million. Net cash used in investing activities during 2010 also exceeded net cash provided by operating activities by $393.0 million, however, in 2009, net cash provided by operating activities of $1,149.4 million exceeded net cash used in investing activities of $1,146.4 million by $3.0 million. The reason that 2009 operating cash flows exceeded investing activities was a result of the economic downturn, in which the Company limited capital expenditures to approximate internally generated cash flow. For 2011, long-term debt increased by a net change of $207.1 million while short-term debt decreased by $58.5 million. At December 31, 2011, long-term debt consisted of $606.5 million outstanding under QEP's revolving credit facility and $1,072.9 million in senior notes (including $5.5 million of net original issue discount). At December 31, 2011, combined short-term and long-term debt was 33% and equity was 67% of total capital. All intercompany loans between Questar and QEP, which have been historically reported as notes payable in the Consolidated Balance Sheets, were repaid on June 30, 2010, in conjunction with the Spin-off.

Credit Facility

During the third quarter of 2011, QEP entered into a new revolving credit facility, which matures in August 2016 and replaced the previous $1.0 billion credit facility. The terms of the new credit facility provide for loan commitments of $1.5 billion from a syndicate of financial institutions. The new credit facility provides for borrowings at short-term interest rates and contains customary covenants and restrictions. The agreement also contains the provisions which 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. QEP increased its borrowings under its credit facility from $400.0 million as of December 31, 2010, to $606.5 million as of December 31, 2011. QEP's weighted-average interest rate on borrowings from its credit facilities was 3.05%. Proceeds from borrowings under the credit facility were used to refinance outstanding amounts under the Company's previous credit facility and will be used for general corporate purposes, including working capital and capital expenditures. The credit agreement includes financial covenants (i) limiting the ratio of the consolidated funded debt of the Company to the sum of consolidated funded debt plus shareholders' equity to not more than 0.6 to 1, (ii) limiting the ratio of the consolidated funded debt of the Company to the Company's consolidated EBITDA to not more than 3.5 to 1, and (iii) if the Company's debt ratings fall below a certain level, limiting the Company' total consolidated funded debt to a specified aggregate amount. At December 31, 2011, QEP was in compliance with all of its debt covenants. At February 17, 2012, QEP had $614.0 million outstanding under its revolving credit facility and $4.1 million of letters of credit issued.

Senior Notes

The Company's senior notes outstanding as of December 31, 2011 totaled $1,078.4 million principal amount and are comprised of four issues as follows:

- $176.8 million 6.05% Senior Notes due September 2016
- $138.6 million 6.80% Senior Notes due April 2018
- $138.0 million 6.80% Senior Notes due March 2020
- $625.0 million 6.875% Senior Notes due March 2021

In August 2010, the Company purchased $638.0 million principal amount of its senior notes and paid required premium and accrued interest pursuant to the requirement in the notes' indenture relating to a change of control. The Company used cash on hand and proceeds from its $1.0 billion revolving credit facility and its $500.0 million term loan to purchase all of the tendered notes. Subsequent to the purchase of the tendered notes, the Company issued $625.0 million principal amount of senior notes due 2021. The notes were issued at a discount, resulting in gross proceeds of $619.2 million which were used to pay fees and expenses associated with the issuance and to refinance a portion of the indebtedness incurred under the term loan and revolving credit facilities to purchase the tendered senior notes. Upon repayment of the term loan, commitments under the term loan were terminated.

Capital Expenditures

During the year ended December 31, 2011, cash capital expenditures decreased 3% to $1,431.1 million, which included $48.0 million for property acquisitions, compared to $1,469.0 million during the same period in 2010. The decrease was driven by reduced development drilling in the Haynesville/Cotton Valley and Pinedale Anticline, partially offset by higher capital investment in development drilling in the Midcontinent and the Rockies Legacy divisions. Approximately $1,295.5 million was used in QEP Energy, including $1,247.5 million in drilling and completion and other expenditures and $48.0 million in property acquisition costs. QEP Field Services 2011 capital expenditures of $130.1 million were used to expand capacity at the Company's gathering, processing and treating facilities including the Blacks Fork II cryogenic gas processing plant which was completed in July of 2011. In 2010, capital expenditures were $272.1 million higher than in the comparable 2009 period. The increase in 2010 was driven by QEP Field Services and its increased investment in its gathering, processing and treating facilities to expand capacity in western Wyoming, eastern Utah and northwest Louisiana. Also contributing to the 2010 increase was QEP Energy's increased capital expenditures due to an increased drilling program in 2010.

In 2012, QEP intends to fund capital expenditures with cash flow from operating activities and borrowings under its revolving credit facility, if needed. As a result of the continued spread between oil and natural gas prices, in 2012 QEP plans to decrease capital expenditures for the Haynesville Shale and other dry gas development areas and increase capital expenditures for higher return projects, including Pinedale, the Bakken, and oil-directed horizontal drilling in the Powder River Basin and Midcontinent and continued development of QEP's Uinta Basin Red Wash liquids-rich gas play. QEP has allocated approximately 88% of its forecasted 2012 drilling and completion capital expenditure budget to oil and liquids-rich natural gas projects in its portfolio. The Company has budgeted approximately $1,450.0 million for capital expenditures in 2012, of which it has allocated $1,280.0 million to QEP Energy. QEP plans to invest approximately $170.0 million in capital expenditures to grow its midstream business, including construction of a new 150 MMcfpd fee-based cryogenic gas processing plant in the Uinta Basin. The aggregate levels of capital expenditures for 2012 and the allocation of those expenditures are dependent on a variety of factors, including drilling results, natural gas and oil 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.

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, 2011, the Company's material off-balance sheet arrangements and transactions included operating lease arrangements, drilling and transportation contracts and undrawn letters of credit. There are no other transactions, arrangements, or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect QEP's liquidity or availability of, or requirements for capital resources. *See* "Contractual Cash Obligations and Other Commitments" below for more information regarding off-balance sheet arrangements.

Contractual Cash Obligations and Other Commitments

In the course of ordinary business activities, QEP enters into a variety of contractual cash obligations and other commitments. The following table summarizes the significant contractual cash obligations as of December 31, 2011:

	Payments Due by Year						
	Total	2012	2013	2014	2015	2016	After 2016
				(in millions)			
Long-term debt [1]	$ 1,684.9	$ -	$ -	$ -	$ -	$ 783.3	$ 901.6
Interest on fixed-rate long-term debt [2]	579.4	72.5	72.5	72.5	72.5	68.9	220.5
Drilling contracts	146.2	70.8	37.2	36.1	2.1	-	-
Transportation contracts	406.8	45.4	44.3	43.3	43.2	41.8	188.8
Asset Retirement Obligations [3]	284.6	15.3	2.9	3.2	2.4	4.0	256.8
Operating leases	59.1	5.6	6.1	5.6	5.7	5.8	30.3
Total	$ 3,161.0	$ 209.6	$ 163.0	$ 160.7	$ 125.9	$ 903.8	$ 1,598.0

[1] Includes $606.5 milllion relating to the Company's revolving credit facility.
[2] Excludes variable rate debt interest payments relating to the Company's revolving credit facility.
[3] These future obligations are estimates of when the liabilities will be settled.
[4] This table excludes the Company's benefit plan liabilities as future payment dates are unknown. See Item 8 of this annual report on Form 10-K, note 11 "Employee Benefits" for additional information.

Critical Accounting Policies, and Estimates

QEP's significant accounting policies are described in Note 1 to the consolidated financial statements included in Item 8 of Part II of its Annual Report. 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.

Gas and Oil Reserves

Gas and oil 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, 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 gas and oil reserves significantly affect the Company's DD&A expense. For example, if estimates of proved reserves decline, the 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 crude oil and natural gas properties exceeds fair value and could result in an impairment charge, which would reduce earnings.

See Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information (Unaudited).

Successful Efforts Accounting for Gas and Oil Operations

The Company follows the successful efforts method of accounting for gas and oil 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.

The capitalized costs of unproved properties are generally combined and amortized over the expected holding period for such properties. Individually significant unproved properties are periodically reviewed for impairment. 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 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.

QEP Energy engages an independent reservoir engineering consultant to prepare estimates of the proved gas and oil 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.

Impairment of Oil and Gas Properties

Proved gas and oil 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 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 gas and oil reserves caused by mechanical problems, faster-than-expected decline of reserves, lease-ownership issues, other-than-temporary decline in gas 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 and operating costs. During the fourth quarter of 2011, QEP recorded an impairment charge of $195.2 million on some of its mature, dry gas, and higher cost properties in both the Northern Region and Southern Region. The impairment charge related to the reduced value of these areas resulting from lower natural gas prices and the current forward curve for natural gas prices.

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 (AROs) relate to the plugging of wells and the related abandonment of oil and gas properties. QEP's AROs 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 AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimate timing of abandonment.

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 natural 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 AOCI depending on the structure of the derivative. The Company has historically 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 are recorded on the balance sheet and in AOCI until the underlying gas or oil is produced. When a derivative is terminated before its contract expires, the associated gain or loss is recognized in income over the life of the previously hedged production. Changes in the fair value of derivative contracts that do not qualify for hedge accountings are included as part of operating income in the Consolidated Statement of Income.

As of December 31, 2011, QEP designated most of its natural gas, oil and NGL derivative contracts as cash flow hedges, whose unrealized fair value gains and losses were recorded to AOCI. Effective January 1, 2012, the Company has elected to de-designate all of its natural gas, oil and NGL derivative contracts that had previously been designated as cash flow hedges at December 31, 2011 and have elected to discontinue hedge accounting prospectively. Accordingly, changes in the fair value of commodity derivative contracts will be reported each quarter in earnings as unrealized gains (losses). See Part II, Item 8, footnote 1 "Summary of Significant Accounting Policies" of this 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 for all gas, oil and NGL 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 an imbalance in excess of its share of remaining reserves in an underlying property. QEP Marketing presents revenues on a gross revenue basis. 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.

Environmental Obligations and Other Contingencies

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 or other contingent matters and actual costs may vary significantly.

Benefit Plan Obligations

QEP has non-contributory defined-benefit pension plans, including both qualified and supplemental plans. 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.

Share-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.

Recent Accounting Developments

See Recent Accounting Developments in Note 1 of the footnotes to the consolidated financial statements, in Item 8, Part II of this annual report.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

QEP's primary market-risk exposure arises from changes in the market price for natural gas, oil and NGL, and to a lesser extent, volatility in interest rates. These risks can affect revenues and cash flows from operating, investing and financing activities. QEP Energy and QEP Marketing 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. If energy prices decline or increase significantly, revenues and cash flow may significantly decline or increase. In addition, a non-cash write-down of the Company's oil and gas properties may be required if future oil and natural gas commodity prices experience a sustained, significant decline. A sensitivity analysis of the Company's commodity price related derivative instruments to changes in the price of the underlying commodities is presented below.

Commodity Price Risk Management

QEP's subsidiaries use 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 Company's risk management policies provide for the use of derivative instruments to manage this risk. The types of commodity derivative instruments utilized by the Company include fixed-price swaps, costless collars, and basis-only swaps. The volume of commodity derivative instruments utilized by the Company may vary from year-to-year. Both exchange and over-the-counter traded commodity derivative instruments may be subject to margin deposit requirements, and the Company may be required from time to time to deposit cash or provide letters of credit with exchange brokers or its counterparties in order to satisfy these margin requirements. 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, 2011, QEP held sale and purchase commodity price derivative contracts totaling 213.0 million MMBtu of natural gas, 2.0 million barrels of oil, and 53.9 million gallons of NGL. As of December 31, 2010, the QEP derivative contracts covered 247.5 million MMBtu of natural gas and 1.1 million barrels of oil. Changes in the fair value of derivative contracts from December 31, 2010 to December 31, 2011, are presented below:

	Cash Flow Hedges	Basis-Only Swaps	Total
		(in millions)	
Net fair value of gas and oil derivative contracts outstanding at Dec. 31, 2010	$ 356.2	$ (117.7)	$ 238.5
Contracts settled	(311.1)	117.7	(193.4)
Change in gas and oil prices on futures markets	214.7	-	214.7
Contracts added	136.1	-	136.1
Net fair value of gas, oil and NGL derivative contracts outstanding at December 31, 2011	**$ 395.9**	**$ -**	**$ 395.9**

A table of the net fair value of gas, oil, and NGL derivative contracts that are scheduled to settle over the next five years as of December 31, 2011, is shown below. Derivatives representing approximately 69% of the net fair value will settle in the next twelve months and will be reclassified from AOCI to the Consolidated Statements of Income:

	Cash Flow Hedges	Basis-Only Swaps	Total
		(in millions)	
Contracts maturing by December 31, 2012	$ 272.4	$ -	$ 272.4
Contracts maturing between January 1, 2013 and December 31, 2013	123.5	-	123.5
Contracts maturing between January 1, 2014 and December 31, 2014	-	-	-
Contracts maturing between January 1, 2015 and December 31, 2015	-	-	-
Net fair value of gas, oil and NGL derivative contracts outstanding at December 31, 2011	**$ 395.9**	**$ -**	**$ 395.9**

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

	December 31, 2011	December 31, 2010
	(in millions)	
Net fair value - asset (liability)	**$ 395.9**	$ 238.5
Fair value if market prices of gas, oil and NGL and basis differentials decline by 10%	**490.3**	356.2
Fair value if market prices of gas, oil and NGL and basis differentials increase by 10%	**301.4**	132.1

Utilizing the actual derivative contractual volumes, a 10% increase in underlying commodity prices would reduce the fair value of these instruments by $94.5 million, while a 10% decrease in underlying commodity prices would increase the fair value of these instruments by $94.4 million. However, a gain or loss would eventually 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 Managements' Discussion and Analysis of Financial Condition and Results of Operations-Commodity Derivative's Impact under Part I, Item 2 and see Note 6 – Derivative Contracts under Part II, Item 8 of this Annual Report on Form 10-K.

Credit Risk

QEP requests credit support and, in some cases, financial guarantees, letters of credit or prepayment from companies that pose unfavorable credit risks. The Company's five largest customers accounted for 32%, and 27% in aggregate, of QEP revenues before elimination of intercompany transactions in 2011 and 2010, and their accounts were current at December 31, 2011. However, each of the five largest customers sales were below 10% of QEP revenues.

Interest-Rate Risk Management

The Company's ability to borrow and the rates quoted by lenders can be adversely affected by the illiquid credit markets as described in Item 1A. Risk Factors of Part I of this Annual Report on Form 10-K. The Company's credit facility has floating interest rates and as such, exposes QEP to interest rate risk. If interest rates were to increase 10% over their average 2011, 2010 and 2009 levels and at QEP's average level of borrowing for those years, QEP's annualized interest expense would increase by $1.3 million, $0.5 million and $0.3 million, respectively, or less than 2% of the Company's total interest expense in each year.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Financial Statements:

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

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

We have audited the accompanying consolidated balance sheets of QEP Resources, Inc. as of December 31, 2011 and 2010, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2011. Our audits also included the financial statement schedule listed in the Index at Item 8. 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 financial position of QEP Resources, Inc. at December 31, 2011 and 2010, and the consolidated results of its operations and its cash flows for each of the three years in the 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.

As discussed in Note 1 to the consolidated financial statements, during 2009, the Company adopted a new accounting standard relating to the presentation of noncontrolling interests in consolidated subsidiaries and the Company adopted new oil and gas reserve estimation and disclosure requirements.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), QEP Resources, Inc.'s internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2012 expressed an unqualified opinion thereon.

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

Report of Independent Registered Public Accounting Firm

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

We have audited QEP Resources, Inc.'s internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). QEP Resources, Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Assessment of Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, QEP Resources, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the COSO criteria**.**

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of QEP Resources, Inc. as of December 31, 2011 and 2010, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2011, of QEP Resources, Inc. and our report dated February 24, 2012, expressed an unqualified opinion thereon.

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

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QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2011	2010	2009
	(in millions, except per share amounts)		
REVENUES			
Natural gas sales	**$ 1,239.1**	$ 1,205.3	$ 1,187.2
Oil sales	**324.2**	198.1	141.3
NGL sales	**129.7**	47.9	22.5
Gathering, processing and other	**380.9**	251.3	218.4
Purchased gas and oil sales	**1,085.3**	598.0	441.8
Total Revenues	**3,159.2**	2,300.6	2,011.2
OPERATING EXPENSES			
Purchased gas and oil expense	**1,077.1**	589.3	427.8
Lease operating expense	**145.2**	125.0	125.5
Natural gas, oil and NGL transportation and other handling costs	**102.2**	54.2	38.7
Gathering, processing and other	**107.3**	83.2	76.2
General and administrative	**123.2**	107.2	91.7
Separation costs	**-**	13.5	-
Production and property taxes	**105.4**	82.5	62.9
Depreciation, depletion and amortization	**765.4**	643.4	559.1
Exploration expenses	**10.5**	23.0	25.0
Abandonment and impairment	**218.4**	46.1	20.3
Total Operating Expenses	**2,654.7**	1,767.4	1,427.2
Net gain from asset sales	**1.4**	12.1	1.5
OPERATING INCOME	**505.9**	545.3	585.5
Interest and other income (loss)	**4.1**	2.3	4.5
Income from unconsolidated affiliates	**5.5**	3.0	2.7
Unrealized and realized loss on basis-only swaps	**-**	-	(189.6)
Loss from early extinguishment of debt	**(0.7)**	(13.3)	-
Interest expense	**(90.0)**	(84.4)	(70.1)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	**424.8**	452.9	333.0
Income taxes	**(154.4)**	(167.0)	(117.6)
INCOME FROM CONTINUING OPERATIONS	**270.4**	285.9	215.4
Discontinued operations, net of income tax	**-**	43.2	80.7
NET INCOME	**270.4**	329.1	296.1
Net income attributable to noncontrolling interest	**(3.2)**	(2.9)	(2.6)
NET INCOME ATTRIBUTABLE TO QEP	**$ 267.2**	$ 326.2	$ 293.5
Earnings Per Common Share Attributable to QEP			
Basic from continuing operations	**$ 1.51**	$ 1.61	$ 1.23
Basic from discontinued operations	**-**	0.25	0.46
Basic total	**$ 1.51**	$ 1.86	$ 1.69
Diluted from continuing operations	**$ 1.50**	$ 1.60	$ 1.21
Diluted from discontinued operations	**-**	0.24	0.46
Diluted total	**$ 1.50**	$ 1.84	$ 1.67
Weighted-average common shares outstanding			
Used in basic calculation	**176.5**	175.3	174.1
Used in diluted calculation	**178.4**	177.3	176.3

See notes accompanying the consolidated financial statements.

QEP RESOURCES, INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2011	2010	2009
		(in millions)	
Net income	**$ 270.4**	$ 329.1	$ 296.1
Other comprehensive income (loss), net of tax:			
Gains (losses) on changes in unrealized fair value of derivatives designated as cash flow hedges [1]	**24.8**	136.7	(254.5)
Pension and other postretirement plans adjustments:			
Net unamortized gain (loss) incurred [2]	**(14.7)**	2.6	-
Prior service cost incurred [3]	-	(33.8)	-
Recognized prior service cost [4]	**3.5**	1.7	-
Total pension and other postretirement plans adjustments	**(11.2)**	(29.5)	-
Other comprehensive income	**13.6**	107.2	(254.5)
Comprehensive income	**284.0**	436.3	41.6
Comprehensive income attributable to noncontrolling interests	**(3.2)**	(2.9)	(2.6)
Comprehensive income attributable to QEP	**$ 280.8**	$ 433.4	$ 39.0

[1] Presented net of income tax expense of $14.7 million, and $81.0 million for the years ended December 31, 2011 and 2010 and net of income tax benefit of $150.6 million for the year ended December 31, 2009, respectively.

[2] Presented net of income tax benefit of $9.2 million for the year ended December 31, 2011, and net of income tax expense of $1.6 million for the year ended December 31, 2010, respectively.

[3] Presented net of income tax benefit of $20.9 million for the year ended December 31, 2010.

[4] Presented net of income tax expense of $2.1 million and $1.0 million for the years ended December 31, 2011 and 2010, respectively.

See notes accompanying the consolidated financial statements.

QEP RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2011	2010
	(in millions)	
ASSETS		
Current Assets		
Cash and cash equivalents	**$ -**	$ -
Accounts receivable, net	**397.4**	269.9
Fair value of derivative contracts	**273.7**	257.3
Inventories, at lower of average cost or market		
Gas, oil and NGL	**16.2**	16.4
Materials and supplies	**87.6**	65.4
Prepaid expenses and other	**43.7**	45.2
Total Current Assets	**818.6**	654.2
Property, Plant and Equipment (successful efforts method for gas and oil properties)		
Proved properties	**8,172.4**	6,874.3
Unproved properties, not being depleted	**326.8**	322.0
Midstream field services	**1,463.6**	1,360.5
Marketing and other	**49.8**	44.5
Total Property, Plant and Equipment	**10,012.6**	8,601.3
Less Accumulated Depreciation, Depletion and Amortization		
Exploration and production	**3,339.2**	2,454.4
Midstream field services	**297.5**	244.6
Marketing and other	**14.6**	12.3
Total Accumulated Depreciation, Depletion and Amortization	**3,651.3**	2,711.3
Net Property, Plant and Equipment	**6,361.3**	5,890.0
Investment in unconsolidated affiliates	**42.2**	44.5
Other Assets		
Goodwill	**59.5**	59.6
Fair value of derivative contracts	**123.5**	120.8
Other noncurrent assets	**37.6**	16.2
Total Other Assets	**220.6**	196.6
TOTAL ASSETS	**$ 7,442.7**	$ 6,785.3

See notes accompanying the consolidated financial statements.

QEP RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
	(in millions)	
LIABILITIES AND EQUITY		
Current Liabilities		
Checks outstanding in excess of cash balances	**$ 29.4**	$ 19.5
Accounts payable and accrued expenses	**457.3**	332.2
Production and property taxes	**40.0**	18.9
Interest payable	**24.4**	28.1
Fair value of derivative contracts	**1.3**	139.3
Deferred income taxes	**85.4**	27.8
Current portion of long-term debt	**-**	58.5
Total Current Liabilities	**637.8**	624.3
Long-term debt, less current portion	**1,679.4**	1,472.3
Deferred income taxes	**1,484.7**	1,377.7
Asset retirement obligations	**163.9**	148.3
Fair value of derivative contracts	**-**	0.3
Other long-term liabilities	**124.8**	99.3
Commitments and contingencies		
EQUITY		
Common stock - par value $0.01 per share; 500.0 million shares authorized; 177.2 million and 175.9 million shares issued at December 31, 2011 and 2010, respectively	**1.8**	1.8
Treasury stock - 0.4 million and 0.1 million shares at December 31, 2011 and 2010, respectively	**(13.1)**	(3.8)
Additional paid-in capital	**431.4**	398.0
Retained earnings	**2,673.5**	2,420.0
Accumulated other comprehensive income	**207.9**	194.3
Total Common Shareholders' Equity	**3,301.5**	3,010.3
Noncontrolling interest	**50.6**	52.8
Total Equity	**3,352.1**	3,063.1
TOTAL LIABILITIES AND EQUITY	**$ 7,442.7**	$ 6,785.3

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)				
Balances at December 31, 2008	173.6	$ 1.7	-	$ -	$ 144.5	$ 2,262.1	$ 341.6	$ 29.5	$ 2,779.4
Questar common stock issued, net of repurchases	1.0	-	-	-	-	-	-	-	-
2009 net income	-	-	-	-	-	293.5	-	2.6	296.1
Dividends paid	-	-	-	-	-	(17.4)	-	-	(17.4)
Share-based compensation	-	-	-	-	13.9	-	-	-	13.9
Consolidation of noncontrolling interest	-	-	-	-	(28.5)	-	-	28.5	-
Tax on equity adjustment	-	-	-	-	(3.1)	-	-	-	(3.1)
Distribution of noncontrolling interest	-	-	-	-	-	-	-	(5.7)	(5.7)
Change in unrealized fair value of derivatives, net of tax	-	-	-	-	-	-	(254.5)	-	(254.5)
Balances at December 31, 2009	174.6	1.7	-	-	126.8	2,538.2	87.1	54.9	2,808.7
Questar common stock issued, net of repurchases	0.4	-	-	-	-	-	-	-	-
2010 net income	-	-	-	-	-	326.2	-	2.9	329.1
Dividends paid	-	-	-	-	-	(15.9)			(15.9)
Share-based compensation	0.9	0.1	(0.1)	(3.9)	23.3	-	-	-	19.5
Equity from Questar		-	-	-	250.0	-	-	-	250.0
Transfer Wexpro to Questar	-	-	-	-	(2.0)	(428.5)	-	-	(430.5)
Distribution of noncontrolling interest	-	-	-	-	-	-	-	(5.0)	(5.0)
Change in unrealized fair value of derivatives, net of tax	-	-	-	-	-	-	136.7	-	136.7
Change in pension and postretirement liability, net of tax	-	-	-	-	-	-	(29.5)	-	(29.5)
Balances at December 31, 2010	175.9	1.8	(0.1)	(3.9)	398.1	2,420.0	194.3	52.8	3,063.1
2011 net income	-	-	-	-	-	**267.2**	-	**3.2**	**270.4**
Dividends paid	-	-	-	-	-	**(14.1)**	-	-	**(14.1)**
Share-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	-	-	-	-	-	-	**24.8**	-	**24.8**
Change in pension and postretirement liability, net of tax							**(11.2)**	-	**(11.2)**
Balances at December 31, 2011	**177.2**	**$ 1.8**	**(0.4)**	**$ (13.1)**	**$ 431.4**	**$ 2,673.5**	**$ 207.9**	**$ 50.6**	**$ 3,352.1**

See notes accompanying the consolidated financial statements.

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QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2011	2010	2009
		(in millions)	
OPERATING ACTIVITIES			
Net income	**$ 270.4**	$ 329.1	$ 296.1
Discontinued operations, net of income tax	-	(43.2)	(80.7)
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**765.4**	643.4	559.1
Deferred income taxes	**156.8**	188.2	103.3
Abandonment and impairment	**218.4**	46.1	20.3
Share-based compensation	**22.0**	16.1	13.4
Amortization of debt issuance costs and discounts	**4.1**	2.4	1.2
Dry exploratory well expense	**0.3**	9.6	4.7
Net gain from asset sales	**(1.4)**	(12.1)	(1.5)
Income from unconsolidated affiliates	**(5.5)**	(3.0)	(2.7)
Distributions from unconsolidated affiliates and other	**7.8**	2.2	1.2
Loss on early extinguishment of debt	**0.7**	13.3	-
Unrealized (gain) loss on basis-only swaps	**(117.7)**	(121.7)	164.0
Changes in operating assets and liabilities			
Accounts receivable	**(144.6)**	(32.6)	42.6
Inventories	**(22.0)**	10.1	13.7
Prepaid expenses	**1.6**	(16.2)	(3.1)
Accounts payable and accrued expenses	**127.8**	4.2	9.9
Federal income taxes	**17.0**	(30.9)	21.2
Other	**(8.5)**	(7.5)	(13.3)
Net Cash Provided by Operating Activities of Continuing Operations	**1,292.6**	997.5	1,149.4
INVESTING ACTIVITIES			
Property acquisitions	**(48.0)**	(109.3)	(221.5)
Property, plant and equipment, including dry exploratory well expense	**(1,383.1)**	(1,359.7)	(975.4)
Other investments	-	-	(1.5)
Proceeds from disposition of assets	**8.2**	25.6	14.2
Change in notes receivable	-	52.9	37.8
Net Cash Used in Investing Activities of Continuing Operations	**(1,422.9)**	(1,390.5)	(1,146.4)
FINANCING ACTIVITIES			
Checks outstanding in excess of cash balances	**9.9**	19.5	-
Long-term debt issued	**591.5**	1,034.4	424.5
Long-term debt issuance costs paid	**(10.6)**	(16.6)	(2.5)
Current portion long-term debt repaid	**(58.5)**	(91.5)	-
Repayments of notes payable	-	(39.3)	(50.1)
Long-term debt repaid	**(385.0)**	(761.5)	(375.0)
Long-term debt extinguishment costs	-	(4.9)	-
Other capital contributions	**2.3**	2.8	-
Equity contribution	-	250.0	-
Dividends paid	**(14.1)**	(7.0)	-
Distribution from Questar	**0.2**	(7.2)	-
Distribution to noncontrolling interest	**(5.4)**	(5.0)	(5.7)
Net Cash Provided by Financing Activities of Continuing Operations	**130.3**	373.7	(8.8)
CASH USED IN CONTINUING OPERATIONS	-	(19.3)	(5.8)
Cash provided by operating activities of discontinued operations	-	68.6	174.4
Cash used in investing activities of discontinued operations	-	(39.9)	(116.2)
Cash used in financing activities of discontinued operations	-	(26.9)	(53.4)
Effect of change in cash and cash equivalents of discontinued operations	-	(1.8)	(4.8)
Change in cash and cash equivalents	-	(19.3)	(5.8)
Beginning cash and cash equivalents	-	19.3	25.1
Ending cash and cash equivalents	**$ -**	$ -	$ 19.3
Supplemental Disclosure of Cash Paid (Received) During the Year for:			
Interest	**$ 93.5**	$ 83.3	$ 62.2
Income taxes	**(28.5)**	14.0	(10.0)

See notes accompanying the consolidated financial statements.

Note 1 – Summary of Significant Accounting Policies

Nature of Business

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

- QEP Energy Company, (QEP Energy) acquires, explores for, develops and produces natural gas, oil, and natural gas liquids (NGL);
- QEP Field Services Company (QEP Field Services) provides midstream field services including natural gas gathering and processing, compressing and treating services for affiliates and third parties; and
- QEP Marketing Company (QEP Marketing) markets affiliate and third-party natural gas and oil, provides risk-management services, and owns and operates an underground gas-storage reservoir.

Operations are focused in the Northern (formerly Rocky Mountain) and Southern (formerly Midcontinent) Regions of the United States. Company headquarters are in Denver, Colorado. Shares of QEP common stock trade on the New York Stock Exchange (NYSE:QEP).

Principles of Consolidation

The consolidated financial statements contain the accounts of QEP and its majority-owned or controlled subsidiaries. The consolidated financial statements were prepared in accordance with 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.

On January 1, 2009, QEP adopted “Noncontrolling Interests in Consolidated Financial Statements” (ASC 810-10-65-1) for the accounting, reporting and disclosure of noncontrolling interests. The new guidance requires that noncontrolling interest, previously known as minority interest, be clearly identified, labeled, and presented in the consolidated financial statements separate from the parent’s equity; the amount of consolidated net income attributable to the parent and to the noncontrolling interest be clearly identified and presented in the consolidated income statement; changes in a parent’s ownership interest while the parent retains its controlling financial interest in its subsidiary be accounted for consistently; and any retained noncontrolling equity investment in a former subsidiary be initially measured at fair value. The new provisions are applied prospectively from the date of adoption, except for the presentation and disclosure requirements, which are applied retrospectively for all periods presented.

Effective May 18, 2010, Questar Market Resources, Inc., (Market Resources) then a wholly owned subsidiary of Questar Corporation (Questar), merged with and into a newly-formed, wholly owned subsidiary, QEP, 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. The Reincorporation Merger was approved by the boards of directors of Market Resources and QEP and submitted to a vote of, and approved by, the Board of Directors of Questar, as sole shareholder of Market Resources, and by Market Resources, as sole shareholder of QEP on May 18, 2010.

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 one share of Questar common stock held (including fractional shares) at the close of business on the record date. In connection therewith, 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.

The financial information presented in this Annual Report on Form 10-K presents QEP’s financial results as an independent company separate from Questar and reflects Wexpro’s financial condition and operating results as discontinued operations for all periods presented. A summary of discontinued operations can be found in Note 2 to the consolidated financial statements.

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

SEC’s Modernization of Oil and Gas Reporting Requirements

In December 2008, the SEC issued Release No. 33-8995, “Modernization of Oil and Gas Reporting,” which amended the oil and gas disclosures for oil and gas producers contained in Regulations S-K and S-X. The goal of Release No. 33-8995 was to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. The most significant amendments affecting the Company include the following: (i) economic producibility of reserves and discounted cash flows are to be based on the arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period, unless contractual arrangements designate the price to be used; and (ii) reserves may be estimated and categorized through the use of reliable technologies. Release No. 33-8995 is effective for financial statements for fiscal years ending on or after December 31, 2009.

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. Generally, 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, 2011 and 2010, were Uintah Basin Field Services, LLC, (38%) and Three Rivers Gathering, LLC, (50%), both limited liability companies engaged in gathering and compressing natural gas.

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 and liabilities, and the disclosure of contingent assets and liabilities. The Company also incorporates estimates of proved developed and proved natural gas, oil and NGL reserves in the calculation of depreciation, depletion and amortization rates of its gas and oil properties. 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 gas and oil reserves. 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 reflect the impact of price-hedging instruments. Revenues associated with the sale of natural gas and oil are accounted for using the sales method, whereby revenue is recognized as gas and oil is sold to purchasers. A liability is recorded to the extent that the Company has sold volumes in excess of its share of remaining gas and oil reserves in an underlying property. QEP's imbalance obligations at December 31, 2011 and 2010 were $4.9 million and $4.4 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 natural 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."

Regulation of Underground Storage

QEP through Clear Creek Storage Company, LLC, operates an underground gas-storage facility under the jurisdiction of the Federal Energy Regulatory Commission (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.

Cash and Cash Equivalents

Cash equivalents consist principally of repurchase agreements with maturities of three months or less. In almost all cases, the repurchase agreements are highly liquid investments in overnight securities made through commercial-bank accounts that result in available funds the next business day.

Notes Receivable from or Payable to Questar Corporation

Prior to the Spin-off, Questar centrally managed cash. Notes receivable from or payable to Questar represented interest bearing demand notes for cash loaned to or borrowed from Questar until needed for operations. Amounts loaned to Questar earned an interest rate that was identical to the interest rate paid by the Company for borrowings from Questar. All intercompany loans between Questar and QEP were repaid on June 30, 2010, in conjunction with the Spin-off.

Property, Plant and Equipment

Property, plant and equipment balances are stated at historical cost. 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:

Gas and oil properties

QEP Energy uses the successful efforts method to account for gas and oil 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 generally combined and amortized over the expected holding period for such properties. Capitalized costs of unproved properties are reclassified as proved property when related proved reserves are determined or charged against the impairment allowance when abandoned. QEP Energy proved and unproved leaseholds had a net book value of $1,035.7 million at December 31, 2011, and $1,130.5 million at December 31, 2010.

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 gas and oil 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 gas and oil reserves. 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. Capitalized costs of exploratory wells that have found proved gas and oil reserves and capitalized development costs are depreciated using the unit-of-production method based on estimated proved developed reserves on a field basis. The Company capitalizes an estimate of the fair value of future abandonment costs. Future abandonment costs, less estimated future salvage values, are depreciated over the life of the related asset using a unit-of-production method.

Depreciation, depletion and amortization for the remaining Company 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 years to 30 years
Leasehold improvements	3 years to 10 years
Service, transportation and field service equipment	3 years to 7 years
Furniture and office equipment	3 years to 7 years

Impairment of Long-Lived Assets

Proved gas and oil 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 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 gas and oil reserves caused by mechanical problems, faster-than-expected decline of reserves, lease-ownership issues, other-than-temporary decline in gas 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 probable and possible reserves. Cash flow estimates relating to future cash flows from probable and possible reserves are reduced by additional risk-weighting factors. During the fourth quarter of 2011, QEP recorded a non-cash price-related impairment charge of $195.2 million on some of its mature, dry gas, and higher cost properties in both the Northern and Southern Regions. The impairment charge related to the reduced value of these areas resulting from lower natural gas prices and the current forward curve for natural gas prices. The assets were written down to their estimated fair values. Of the $195.2 million impairment charge, $163.5 million were related to properties in the Northern Region with the remaining $31.7 million related to properties in the Southern Region.

The Company also performs periodic assessments of individually significant unproved gas and oil properties for impairment and recognizes a loss at the time of impairment. In determining whether a significant unproved property is impaired the Company considers numerous factors including, but not limited to, current exploration plans, favorable or unfavorable exploration activity on adjacent leaseholds, in-house geologists' evaluations of the lease, and the remaining lease term.

Asset Retirement Obligations

Asset retirement obligations (AROs) 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. AROs 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 AROs change, an adjustment is recorded to both the asset retirement obligation and the long-lived asset. Revisions to estimated AROs 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 $3.0 million in 2011 and $3.1 million in 2010. There was no capitalized interest during 2009.

Goodwill and Other Intangible Assets

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. Goodwill and indefinite-lived intangible assets are tested for impairment at a minimum of once a year or when a triggering event occurs. If a triggering event occurs, the undiscounted net cash flows of the intangible asset or entity to which the goodwill relates are evaluated. Impairment is indicated if undiscounted cash flows are less than the carrying value of the assets. The amount of the impairment is measured using a discounted-cash flow model considering future revenues, operating costs, a risk-adjusted discount rate and other factors.

Derivative Instruments

The Company may elect to designate a derivative instrument as a hedge of exposure to changes in fair value or cash flows. If the hedged exposure is a fair value exposure, the gain or loss on the derivative instrument is recognized in earnings in the period of the change together with the offsetting gain or loss from the change in fair value of the hedged item. If the hedged exposure is a cash flow exposure, the effective portion of the gain or loss on the derivative instrument is reported initially as a component of AOCI and subsequently reclassified into earnings when the forecasted transaction affects earnings. Any amount excluded from the assessment of hedge effectiveness, as well as the ineffective portion of the gain or loss, is reported in the current period income statement. A derivative instrument qualifies as a cash flow hedge if all of the following tests are met:

- The item to be hedged exposes the Company to price risk.
- The derivative reduces the risk exposure and is designated as a hedge at the time the Company enters into the contract.
- At the inception of the hedge and throughout the hedge period, there is a high correlation between changes in the market value of the derivative instrument and the fair value of the underlying hedged item.

When the designated item associated with a derivative instrument matures, is sold, extinguished or terminated, derivative gains or losses are included in income in the same period that the underlying production or other contractual commitment is delivered. When a derivative instrument is associated with an anticipated transaction that is no longer probable, the gain or loss on the derivative is reclassified from other comprehensive income and recognized currently in the results of operations. When a derivative is terminated before its contract expires, the associated gain or loss is recognized in income over the life of the previously hedged production.

As of December 31, 2011, QEP designated most of its natural gas, oil and NGL derivative contracts as cash flow hedges, whose unrealized fair value gains and losses were recorded to AOCI. Effective January 1, 2012, the Company has elected to de-designate all of its natural gas, oil and NGL derivative contracts that had previously been designated as cash flow hedges and has elected to discontinue hedge accounting prospectively.

As a result, subsequent to December 31, 2011, QEP will recognize all gains and losses from prospective changes in natural gas, oil and NGL derivative fair values immediately in earnings rather than deferring any such amounts in AOCI. 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 on January 1, 2012, such mark-to-market values at December 31, 2011 are frozen in AOCI as of the de-designation date and will be reclassified into earnings in future periods as the original hedged transactions occur and effect earnings. QEP expects to reclassify into earnings from AOCI the frozen value related to de-designated natural gas, oil and NGL hedges during 2012 and 2013.

Physical Contracts

Physical hedge contracts have a nominal quantity and a fixed price. Contracts representing both purchases and sales settle monthly based on quantities valued at a fixed price. Purchase contracts fix the purchase price paid and are recorded as cost of sales in the month the contracts are settled. Sales contracts fix the sales price received and are recorded as revenues in the month they are settled. Due to the nature of the physical market, there is a one-month delay for the cash settlement. QEP accrues for the settlement of contracts in the current month's revenues and cost of sales.

Financial Contracts

Financial contracts are contracts that are net settled in cash without delivery of product. Financial contracts also have a nominal quantity and exchange an index price for a fixed price, and are net settled with the brokers as the price bulletins become available. Financial contracts are recorded in revenues or cost of sales in the month of settlement.

Basis-Only Swaps

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 Rocky Mountain and Midcontinent regions 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 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.

Bad debt expense associated with accounts receivable for the year ended December 31, 2011 and 2009 was $0.2 million and $0.4 million compared with a credit of $0.3 million in 2010. The allowance for bad-debt expenses was $1.7 million at December 31, 2011, and $2.3 million at December 31, 2010.

Income Taxes

Prior to the Spin-off, Questar and its subsidiaries filed consolidated federal income tax returns. QEP accounts for income tax expense on a separate-return basis and records tax benefits as they are generated. 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 at the end of the twelve-month periods ended December 31, 2011, 2010 and 2009. The federal income tax returns for 2010 and 2009 are currently under examination by the Internal Revenue Service. Income tax returns for 2011 have not yet been filed. Most state tax returns for 2008 and subsequent years remain subject to examination.

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. During the first quarter of 2009, the Company adopted the updated provisions of ASC 260, "Earnings Per Share." ASC 260 addresses whether instruments granted in share-based payment transactions are participating securities and therefore have a potential dilutive effect on EPS. The adoption was applied retrospectively and did not have a material effect on the Company's EPS calculations.

Unvested share-based payment awards that contain nonforfeitable 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 nonforfeitable 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. Consequently, in periods of net loss, the two-class method will not have an effect on the Company's basic earnings per share. 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,		
	2011	2010	2010
	(in millions)		
Weighted-average basic common shares outstanding	**176.5**	175.3	174.1
Potential number of shares issuable under the Long-term Stock Incentive Plan	**1.9**	2.0	2.2
Average diluted common shares outstanding	**178.4**	177.3	176.3

Share-Based Compensation

QEP issued 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 share-based compensation costs with graded-vesting periods. Stock options for participants have terms ranging from five to ten years with a majority issued with a seven year term. Options held by employees generally vest in three or four equal, annual installments. Restricted shares vest in equal installments over a specified number of years after the grant date with the majority vesting in three or four years. Non-vested restricted shares have voting and dividend rights; however, sale or transfer is restricted. At the time of the Spin-off, all outstanding options and restricted stock were bifurcated. For a summary of LTSIP transactions see Note 10—Share-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.

Environmental Contingencies

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.

Comprehensive Income

Comprehensive income is the sum of net income attributable to QEP as reported in the Consolidated Statements of Income and changes in the components of other comprehensive income. Other comprehensive income includes certain items that are recorded directly to equity and classified as accumulated other comprehensive income (AOCI). One component of other comprehensive income is changes in the market value of commodity-based derivative instruments that qualify for hedge accounting. Income or loss associated with commodity-based derivative instruments that qualify for hedge accounting is realized when the natural gas, oil or NGL underlying the derivative instrument is sold. Comprehensive income also includes changes in the under-funded portion of the defined benefit pension plans and other postretirement benefits plans and changes in deferred income taxes on such amounts. These transactions are not 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.

Transportation and other handling costs

During the year ended December 31, 2011, QEP revised its reporting of transportation and handling costs to appropriately reflect revenues in accordance with GAAP and industry practice. Transportation and handling costs, previously netted against revenues, have been recast on the Consolidated Income Statement from revenues to "Natural gas, oil and NGL transportation and other handling costs" for all periods presented. The impact of this revision is immaterial to the accompanying financial statements and has no effect on net income.

Recent Accounting Developments

In September of 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-08, which amends the guidance on testing goodwill for impairment. The new guidance provides entities that are testing goodwill the option of performing a qualitative assessment before calculating the fair value of the reporting unit. If, according to a qualitative assessment, the carrying value of the reporting unit is more likely than not less than the fair value, further impairment testing is not required. However, if the qualitative assessment does not provide such conclusive evidence, further testing and calculation of fair value of the reporting unit will be required. The amendments are effective for reporting periods (including interim periods) beginning after December 15, 2011. The adoption of this ASU did not have a material impact on the financial statements of QEP.

In June of 2011, the FASB issued ASU 2011-05, which revises the manner in which entities are able to present the components of comprehensive income in their financial statements. The new guidance requires entities to report the components of comprehensive income in either (1) a continuous statement of comprehensive income or (2) two separate but consecutive statements. However, this ASU does not change the items that are reported in other comprehensive income. The amendments are effective for reporting periods (including interim periods) beginning after December 15, 2011. The adoption of this ASU required minor disclosure changes to QEP's financial statements and footnotes.

In May of 2011, the FASB issued ASU 2011-04, which provides converged guidance on how to measure fair value and requires additional disclosures relating to fair value measurements. Most of the amendments created by this ASU are to bridge the gap between GAAP and International Financial Reporting Standards. However some of the amendments may change how the current fair value measurement guidance is applied. In addition, the ASU expands the qualitative and quantitative fair value disclosure requirements, with most of these additional disclosures pertaining to Level 3 measurements. The amendments are effective for reporting periods (including interim periods) beginning after December 15, 2011. The adoption of this ASU did not have a material impact on QEP's financial statements or disclosures.

In December 2011, the FASB issued ASU 2011-11, which enhances disclosure requirements regarding an entity's financial instruments and derivative instruments that are offset or subject to 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. The amendments are required for annual reporting periods beginning after January 1, 2013 and interim periods within those annual periods. QEP is evaluating the impact of this ASU on its disclosure requirements.

Note 2 – Discontinued Operations

Wexpro's operating results prior to the Spin-off are reflected in this Annual Report on Form 10-K as discontinued operations and summarized below:

	Year Ended December 31,		
	2011	2010	2009
	(in millions, except per share amounts)		
Revenues	$ -	$ 131.2	$ 242.9
Income before income taxes	-	67.4	126.9
Income taxes	-	(24.2)	(46.2)
Discontinued operations, net of income taxes	$ -	$ 43.2	$ 80.7
Earnings per common share attributable to QEP			
Basic from discontinued operations	$ -	$ 0.25	$ 0.46
Diluted from discontinued operations	-	0.24	0.46

Note 3 – Asset Retirement Obligations

QEP records asset retirement obligations (ARO) 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 gas and oil wells, production facilities and certain other properties. The fair values of such costs are estimated by Company personnel based on abandonment costs of similar properties and depreciated over the life of the related assets. Revisions to 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. Income or expense resulting from the settlement of ARO liabilities is included in net gain or (loss) from asset sales in the Consolidated Statements of Income. Changes in ARO were as follows:

	2011	2010
	(in millions)	
ARO liability at January 1,	$ **148.3**	$ 124.7
Accretion	**9.7**	8.8
Liabilities incurred	**7.9**	17.0
Liabilities settled	**(2.0)**	(2.2)
ARO liability at December 31,	$ **163.9**	$ 148.3

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. All of these costs have been capitalized for less than one year after the completion of drilling.

	2011	2010	2009
		(in millions)	
Balance at January 1,	$ **13.6**	$ 51.7	$ 17.0
Additions to capitalized exploratory well costs pending the determination of proved reserves	-	12.2	51.7
Reclassifications to property, plant and equipment after the determination of proved reserves	**(8.3)**	(50.3)	(14.3)
Capitalized exploratory well costs charged to expense	**(0.3)**	-	(2.7)
Balance at December 31,	$ **5.0**	$ 13.6	$ 51.7

Note 5—Fair Value Measurements

QEP measures and discloses fair values in accordance with the provisions of ASC 820 “Fair Value Measurements and Disclosures.” This guidance defines fair value in applying GAAP, establishes a framework for measuring fair value and expands disclosures about fair-value measurements, 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. QEP’s Level 2 fair value measurements consist of fixed-price swaps of natural gas, oil and NGL. Level 3 inputs are unobservable inputs for the asset or liability. QEP’s Level 3 measurements are made up of costless collars for natural gas and oil. The Level 2 fair value of derivative contracts (see Note 6) is based on market prices posted on the NYMEX on the last trading day of the reporting period and industry-standard discounted cash flow models. The Level 3 fair value of derivative contracts is based on NYMEX market prices in combination with unobservable volatility inputs and industry-standard option pricing 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.

Certain of QEP’s derivative instruments, however, 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 a counterparty exists.

QEP did not have any assets or liabilities measured at fair value on a non-recurring basis, other than ARO's, at December 31, 2011 and 2010. The fair values of assets and liabilities at December 31, 2011, are shown in the table below:

	Fair Value Measurements December 31, 2011			
	Level 2	Level 3	Netting Adjustments	Total
	(in millions)			
Assets				
Derivative contracts - short term	**$ 284.1**	**$ -**	**$ (10.4)**	**$ 273.7**
Derivative contracts - long term	**123.5**	**-**	**-**	**123.5**
Total assets	**$ 407.6**	**$ -**	**$ (10.4)**	**$ 397.2**
Liabilities				
Derivative contracts - short term	**$ 11.7**	**$ -**	**$ (10.4)**	**$ 1.3**
Derivative contracts - long term	**-**	**-**	**-**	**-**
Total liabilities	**$ 11.7**	**$ -**	**$ (10.4)**	**$ 1.3**

The fair values of assets and liabilities at December 31, 2010, are shown in the table below:

	Fair Value Measurements December 31, 2010			
	Level 2	**Level 3**	**Netting Adjustments**	**Total**
	(in millions)			
Assets				
Derivative contracts - short term	$ 374.6	$ 37.9	$ (155.2)	$ 257.3
Derivative contracts - long term	121.1	-	(0.3)	120.8
Total assets	$ 495.7	$ 37.9	$ (155.5)	$ 378.1
Liabilities				
Derivative contracts - short term	$ 292.9	$ 1.6	$ (155.2)	$ 139.3
Derivative contracts - long term	0.6	-	(0.3)	0.3
Total liabilities	$ 293.5	$ 1.6	$ (155.5)	$ 139.6

The change in the fair value of Level 3 assets and liabilities is shown below:

	Change in Level 3 Fair Value Measurements	
	2011	2010
	(in millions)	
Balance at January 1,	**$ 36.3**	$ 5.5
Realized gains and losses included in revenues	**25.3**	5.0
Unrealized gains and losses included in other comprehensive income	**(36.3)**	30.8
Settlements	**(25.3)**	(5.0)
Balance at December 31,	$ -	$ 36.3

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	**Estimated Fair Value**	Carrying Amount	Estimated Fair Value
	December 31, 2011		December 31, 2010	
	(in millions)			
Financial assets				
Cash and cash equivalents	**$ -**	**$ -**	$ -	$ -
Financial liabilities				
Checks outstanding in excess of cash balances	**29.4**	**29.4**	19.5	19.5
Long-term debt	**1,679.4**	**1,754.9**	1,530.8	1,575.8

The carrying amounts of cash and cash equivalents, and checks outstanding in excess of cash balances approximate fair value. The fair value of fixed-rate long-term debt is based on the trading levels and dollar prices for the Company's debt at the end of the year. The carrying amount of variable-rate long-term debt approximates fair value.

Note 6 – Derivative Contracts

QEP uses commodity price derivative instruments in the normal course of business. QEP has established policies and procedures for managing commodity price risks through the use of derivative instruments. QEP uses derivative instruments to reduce the impact of downward movements in commodity prices on cash flow, returns on capital, and other financial results. However, these instruments typically limit future gains from favorable price movements. The volume of production subject to 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 derivative contracts for up to 100% of forecasted production from proved reserves. QEP does not enter into derivative instruments for speculative purposes.

QEP uses derivative instruments known as fixed-price swaps and costless collars to realize a known price or range of prices for a specific volume of production delivered into a regional sales point. Costless collars are combinations of put and call options that have a floor price and a ceiling price and payments are made or received only if the settlement price is outside the range between the floor and ceiling prices. QEP's derivative instruments do not require the physical delivery of natural gas, crude oil, or NGL between the parties at settlement. Swap and costless collar 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. In the past, QEP Energy has used natural gas basis-only swaps to protect cash flow, project returns, and other financial results from widening natural gas price basis differentials. As of December 31, 2009, all of the Company's natural gas basis-only swaps had been paired with NYMEX gas fixed-price swaps or costless collars and re-designated as cash flow hedges.

QEP generally enters into derivative instruments that do not have margin requirements or collateral provisions that would require payments prior to the scheduled cash settlement dates. 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 by transacting with multiple counterparties.

All derivative instruments are recorded on the balance sheet as either assets or liabilities measured at their fair values. Reported changes in the fair value of derivatives depend upon whether the derivative instrument qualifies for hedge accounting. A derivative instrument qualifies for hedge accounting if, at inception, the derivative is expected to be highly effective in offsetting the underlying unhedged cash flows. Generally, QEP's derivative instruments are matched to company-owned natural gas, oil and NGL production and are therefore highly effective, thus qualifying as cash flow hedges. Changes in the fair value of effective cash flow hedges are recorded as a component of AOCI in the Consolidated Balance Sheets and reclassified to earnings as natural gas, oil and NGL sales when the underlying contract is settled. Natural gas hedges are typically structured as fixed-price swaps into regional pipelines, locking in basis and hedge effectiveness. Oil hedges are typically structured as NYMEX Calendar fixed-price swaps based at Cushing, Oklahoma. Oil fixed-price swaps inherently contain ineffectiveness because physical sales are priced at the purchaser's published regional prices. NGL hedges are typically structured as Mont Belvieu, Texas fixed-price swaps. Since most of our NGL sales are also based upon Mont Belvieu prices, there is no ineffectiveness. Costless collars qualify for cash flow hedge accounting. Basis-only swaps do not qualify for hedge accounting treatment. Changes in the fair value of these derivative instruments subsequent to their re-designation were recorded in AOCI, while changes in their fair value occurring prior to their re-designation were recorded in the Consolidated Statements of Income. QEP regularly reviews the effectiveness of derivative instruments. The ineffective portion of cash flow hedges and the mark-to-market adjustment in the value of basis-only swaps are recognized in the determination of net income. The effects of derivative transactions are summarized in the tables below:

	Year Ended December 31,		
	2011	2010	2009
		(in millions)	
Effect of derivative instruments designated as cash flow hedges			
Gains (losses) recognized in AOCI for the effective portion of hedges	**$ 350.8**	$ 565.8	$ 214.4
Gains (losses) reclassified from AOCI into income for the effective portion of hedges			
Natural gas sales	**305.5**	353.8	599.3
Oil sales	**1.6**	(8.7)	1.6
Gathering, processing and other	**(0.2)**	-	-
Purchased gas and oil sales	-	-	27.8
Purchased gas and oil expense	**4.3**	3.1	(9.2)
Income (loss) recognized in income for the ineffective portion of hedges			
Interest and other income (loss)	**0.1**	0.2	(0.1)
Effect of derivative instruments not designated as hedges			
Unrealized gain (loss) on basis-only swaps	**117.7**	121.7	(164.0)
Realized (loss) gain on basis-only swaps	**(117.7)**	(121.7)	(25.6)

Based on prices as of December 31, 2011, it is estimated that $171.1 million will be settled and reclassified from AOCI to the Consolidated Statements of Income during the next twelve months. The following table discloses the fair value of derivative contracts on a gross contract basis as opposed to the net contract basis presentation in the Consolidated Balance Sheets.

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	December 31, 2011	December 31, 2010
	(in millions)	
Assets		
Fixed-price swaps	**$ 284.1**	$ 374.6
Costless collars	-	37.9
Fair value of derivative instruments - short term	**$ 284.1**	$ 412.5
Fixed-price swaps	**$ 123.5**	$ 121.1
Costless collars	-	-
Fair value of derivative instruments - long-term	**$ 123.5**	$ 121.1
Liabilities		
Fixed-price swaps	**$ 11.7**	$ 175.2
Costless collars	-	1.6
Basis-only swaps	-	117.7
Fair value of derivative instruments - short term	**$ 11.7**	$ 294.5
Fixed-price swaps	$ -	$ 0.6
Costless collars	-	-
Basis-only swaps	-	-
Fair value of derivative instruments - long-term	$ -	$ 0.6

QEP Energy Production Volumes

The following table sets forth QEP Energy's volumes and average prices for its commodity derivative contracts as of December 31, 2011:

Year	Type of Contract	Index	Total	Average Swap price per unit
			(in millions)	
Natural gas sales (MMbtu)				
2012	Swap	IFNPCR	62.2	$ 5.50
2012	Swap	IFPEPL	7.3	4.70
2012	Swap	NYMEX	69.5	4.93
2013	Swap	IFNPCR	65.7	5.66
2013	Swap	NYMEX	3.7	4.65
Oil sales (Bbls)				
2012	Swap	NYMEX WTI	1.8	$ 97.03
2013	Swap	NYMEX WTI	0.2	105.80
Ethane sales (Gals)				
2012	Swap	Mt. Belvieu Ethane	15.4	$ 0.64
Propane sales (Gals)				
2012	Swap	Mt. Belvieu Propane	7.7	$ 1.28

QEP Field Services NGL Volumes

QEP Field Services enters into commodity derivative transactions to manage price risk on extracted NGL volumes. The following table sets forth QEP Field Services' volumes and swap prices for its commodity derivative contracts as of December 31, 2011:

Year	Type of Contract	Index	Total	Average Swap price per gallon
			(in millions)	
Ethane sales (Gals)				
2012	Swap	Mt. Belvieu Ethane	15.4	$ 0.64
Propane sales (Gals)				
2012	Swap	Mt. Belvieu Propane	15.4	$ 1.36

QEP Marketing Transactions

QEP Marketing enters into commodity derivative transactions to lock in a margin on natural gas volumes placed into storage. The following table sets forth QEP Marketing's volumes and swap prices for its commodity derivative contracts as of December 31, 2011:

Year	Type of Contract	Index	Total	Average Swaps hedged price per MMBtu
			(in millions)	
Natural gas sales (MMbtu)				
2012	Swaps	IFNPCR	3.3	$ 4.41
2013	Swaps	IFNPCR	0.9	4.77
Natural gas purchases (MMbtu)				
2012	Swaps	IFNPCR	0.3	$ 3.54

Note 7 – Debt

As of the indicated dates, the principal amount of QEP's debt, including amounts outstanding under its revolving credit facility, consisted of the following:

	December 31,	
	2011	2010
	(in millions)	
Revolving Credit Facility	**$ 606.5**	$ 400.0
7.5% Senior Notes due 2011	-	58.5
6.05% Senior Notes due 2016	**176.8**	176.8
6.80% Senior Notes due 2018	**138.6**	138.6
6.80% Senior Notes due 2020	**138.0**	138.0
6.875% Senior Notes due 2021	**625.0**	625.0
Total principal amount of debt	**1,684.9**	1,536.9
Less unamortized discount	**(5.5)**	(6.1)
Total long-term debt outstanding	**$ 1,679.4**	$ 1,530.8

Of the total debt outstanding on December 31, 2011, the $606.5 million drawn under the revolving credit facility (described below) due August 25, 2016, and the 6.05% Senior Notes due September 1, 2016, will mature within the next five years.

Credit Arrangements

During the third quarter of 2011, QEP entered into a new revolving credit facility, which matures in August 2016 and replaced the previous $1.0 billion credit facility. The terms of the new credit facility provide for loan commitments of $1.5 billion from a syndicate of financial institutions. The new credit facility provides for borrowing at short-term interest rates and contains customary covenants and restrictions. The agreement also contains provisions that would allow for the amount of the facility to be increased to $2.0 billion and for the maturity to be extended for up to two additional one-year periods. Proceeds from borrowings under the credit facility were used to refinance outstanding amounts under the Company's previous credit facility and will be used for general corporate purposes, including working capital and capital expenditures. In conjunction with the replacement of the previous credit facility, QEP expensed $0.7 million of unamortized financing fees, which are included as a loss on extinguishment of debt on the Consolidated Income Statement. During the year ended December 31, 2011, QEP's weighted-average interest rate on borrowings from its credit facilities was 3.05%. At December 31, 2011 and 2010, QEP was in compliance with all of its debt covenants. At December 31, 2011, QEP had $606.5 million drawn and $4.1 million in letters of credit outstanding under the credit facility.

In conjunction with the Spin-off, QEP entered into a $500.0 million, 364-day term loan agreement with substantially the same initial pricing and terms as its then-existing $1.0 billion revolving credit agreement. Commitments under the term loan were terminated in August 2010 in conjunction with the issuance of $625.0 million of senior notes.

Senior Notes

The Company has $1,078.4 million principal amount of senior notes outstanding with maturities ranging from September 2016 to March 2021 and coupons ranging from 6.05% 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 our ability to, among other things, place liens on its property or assets.

In August 2010, the Company purchased $638.0 million principal amount of its senior notes and paid required premium and accrued interest pursuant to the requirement in the notes' indenture relating to a change of control. The Company used cash on hand and proceeds from its revolving credit facility and term loan to purchase all of the tendered notes. Subsequent to the purchase of the tendered notes, the Company issued $625.0 million principal amount of senior notes due 2021 to refinance a portion of the indebtedness incurred to purchase the tendered senior notes. Proceeds from the senior notes offering were used to repay all of the borrowings outstanding under the term loan and a portion of outstanding borrowings under the Company's revolving credit.

Note 8 – 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,		
	2011	2010	2009
		(in millions)	
Federal			
Current	**$ (5.3)**	$ (16.6)	$ 11.5
Deferred	**153.0**	172.9	101.3
State			
Current	**2.9**	(4.7)	2.6
Deferred	**3.8**	15.4	2.2
Total income tax expense	**$ 154.4**	$ 167.0	$ 117.6

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,		
	2011	2010	2009
		(in millions)	
Federal income taxes statutory rate	**35.0%**	35.0%	35.0%
Increase (decrease) in rate as a result of:			
State income taxes, net of federal income tax benefit	**1.0%**	1.5%	0.9%
Non-deductible Spin-off costs	**0.0%**	0.5%	0.0%
Other	**0.3%**	-0.1%	-0.6%
Effective income tax rate	**36.3%**	36.9%	35.3%

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

	December 31,	
	2011	2010
	(in millions)	
Deferred tax liabilities		
Property, plant and equipment	**$ 1,714.6**	$ 1,458.9
Energy-price derivatives	**45.9**	44.8
Total deferred tax liabilities	**1,760.5**	1,503.7
Deferred tax assets		
NOL and tax credit carryforwards	**232.9**	93.7
Employee benefits and compensation costs	**42.9**	32.3
Total deferred tax assets	**275.8**	126.0
Deferred income taxes - noncurrent	**$ 1,484.7**	$ 1,377.7
Deferred income taxes - current		
Energy-price derivatives	**(101.3)**	(43.9)
Other	**15.9**	16.1
Deferred income taxes - current asset (liability)	**$ (85.4)**	$ (27.8)

Federal and state NOLs and credits increased in 2011 primarily due to bonus depreciation, intangible drilling cost deductions, and QEP no longer being able to offset net operating losses against the taxable income of the formerly affiliated Questar Company and no longer having carryback years with positive taxable income. The amounts and expiration dates of operating loss and tax credit carryforwards at December 31, 2011:

	Expiration Dates	Amounts
	(in millions)	
U.S federal net operating loss carryforwards	2030-2031	$ 187.9
State net operating loss and credit carryforwards	2014-2031	29.3
U.S. alternative minimum tax credit	Indefinite	15.7
Total		$ 232.9

Note 9 – Commitments and Contingencies

QEP is involved in various commercial and regulatory claims and litigation and other legal proceedings that arise in the ordinary course of its business. Management does not believe any of them will have a material adverse effect on the Company's financial position, results of operations or cash flows. A liability is recorded for a loss contingency when its occurrence is probable and damages can be reasonably estimated based on the anticipated most likely outcome. Disclosures are provided for contingencies reasonably likely to occur which would have a material adverse effect on the Company's financial position, results of operations or cash flows. Some of the claims involve highly complex issues relating to liability, damages and other matters subject to substantial uncertainties and, therefore, the probability of liability or an estimate of loss cannot be reasonably determined.

Environmental Claims

United States of America v. QEP Field Services, Civil No. 208CV167, U.S. District Court for Utah. The U.S. Environmental Protection Agency (EPA) alleges that QEP Field Services (f/k/a QGM) violated the Clean Air Act (CAA) and seeks substantial penalties and a permanent injunction involving the manner of operation of five compressor stations located in the Uinta Basin of eastern Utah. Individual members of the Ute Indian Tribe's Business Committee intervened as co-plantiffs asserting the same CAA claims as the federal government. EPA contends that the potential to emit, on a hypothetically uncontrolled basis, for these facilities renders them "major sources" of emissions for criteria and hazardous air pollutants even though controls were installed and operated by QEP Field Services. Categorization of the facilities as "major sources" affects the particular regulatory program and requirements applicable to those facilities. EPA claims that QEP Field Services failed to obtain the necessary major source pre-construction or modification permits, and failed to comply with hazardous air-pollutant regulations for monitoring, testing and reporting, among other requirements. QEP Field Services contends that its facilities have pollution controls installed as part of their operational design that reduce their actual air emissions below major source thresholds, rendering them subject to different regulatory requirements applicable to non-major sources. QEP Field Services has vigorously defended against EPA's claims, and believes that the major source permitting and regulatory requirements at issue can be legally avoided by applying EPA's prior permitting practice for similar facilities elsewhere in Indian Country, among other defenses. Because of the complexities and uncertainties of this legal dispute, it is difficult to predict all reasonably possible outcomes; however, management believes the Company has accrued a reasonable loss contingency that is an immaterial amount, for the anticipated most likely outcome.

*QEP Energy v. U.S. Environmental Protection Agen*cy, No. 09-9538, U.S. Court of Appeals for the 10th Circuit. On July 10, 2009 QEP Energy filed a petition with the U.S. Court of Appeals challenging an administrative compliance order dated May 12, 2009 (Order), issued by EPA which asserts that QEP Energy's Flat Rock 14P well in the Uinta Basin and associated equipment is a major source of hazardous air pollutants and its operation fails to comply with certain regulations of the CAA. The Order required immediate compliance. QEP Energy denied that the drilling and operation of the 14P well and associated equipment violated any provisions of the CAA. QEP and EPA entered into an administrative order on consent, effective June 17, 2011, resolving all disputes associated with prospective CAA compliance at the Flat Rock 14P well. Among other matters, the order requires installation of pollution control equipment to destroy vapors from the well's dehydration equipment and ongoing monitoring and reporting associated with operation of that control equipment.

Commitments

Subsidiaries of QEP have contracted for firm-transportation services with various third-party pipelines through 2040. 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, some of which extend through 2015. Annual payments and the corresponding years for both transportation contracts and drilling contracts are as follows:

	(in millions)
2012	$ 116.2
2013	81.5
2014	79.4
2015	45.3
2016	41.8
After 2016	188.8

QEP rents office space throughout its scope of operations from third-party lessors. Rental expense amounted to $5.0 million, $4.5 million in 2010, and $4.0 million in 2009. Minimum future payments under the terms of long-term operating leases for the Company's primary office locations are as follows:

	(in millions)
2012	$ 5.6
2013	6.1
2014	5.6
2015	5.7
2016	5.8
After 2016	30.3

Note 10 – Share-Based Compensation

QEP issues stock options and restricted shares under its Long-Term Stock Incentive Plan (LTSIP) and performance based share units under its Long-Term Cash Incentive Plan (LTCIP) to certain officers, employees and non-employee directors. Prior to the Spin-off, Questar granted share-based compensation to certain QEP employees using Questar common stock price as the basis. Stock options or restricted stock awards outstanding as of the Distribution Date were adjusted in order to generally preserve the benefits or potential benefits intended under the LTSIP. All such stock options were divided into two separate options, one relating to Questar common stock and one relating to QEP common stock. Each holder of Questar restricted stock was issued additional restricted shares of QEP common stock on a pro rata basis. The exercise price of options and the grant-day prices of restricted shares were modified using the ratio of the June 30, 2010, closing prices of Questar and QEP which were $14.66 or 32.23% and $30.83 or 67.77%, respectively.

QEP recognizes expense over time as stock options or restricted shares vest. Share-based compensation expense amounted to $22.0 million in 2011 compared to $16.1 million in 2010 and $13.4 million in 2009. The tax benefit recognized from share-based compensation expense was $1.5 million and $2.0 million during the years ended December 31, 2011 and 2010. During the year ended December 31, 2009, tax expense of $0.3 million was recognized from the related share-based compensation expense. Deferred share-based compensation is included in additional paid-in capital in the Consolidated Balance Sheets. There were 14.1 million shares available for future grants at December 31, 2011.

Stock Options

QEP uses the Black-Scholes-Merton mathematical model in estimating the fair value of stock options for accounting purposes. 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 for measures the value of options traded on an exchange. The calculated fair value of options granted and major assumptions used in the model at the date of grant are listed below:

	2011	2010	2009
	Stock Option Variables	Stock Option Variables	Range of Stock Option Variables
Fair value of options at grant date	$ 18.80	$ 27.55	$ 31.06 - $35.38
Risk-free interest rate	2.1%	2.3%	1.78% - 2.51%
Expected price volatility	54.7%	30.3%	28.1% - 29.9%
Expected dividend yield	0.21%	1.18%	1.39% - 1.61%
Expected life in years	5.0	5.2	5.0 - 5.0

Stock option transactions under the terms of the LTSIP for the year ended December 31, 2011, are summarized below:

	Options Outstanding	Weighted-Average Price	Aggregate Intrinsic Value
			(in millions)
Balance at December 31, 2010	1,914,922	19.02	
Granted	**202,235**	**39.07**	
Exercised	**(111,797)**	**15.69**	
Forfeited	**(1,666)**	**23.98**	
Balance at December 31, 2011	**2,003,694**	**$ 21.23**	**$ 18.1**

The total intrinsic value of options exercised was $2.7 million during the year ended December 31, 2011.

	Options Outstanding			Options Exercisable			Unvested Options	
Range of Exercise Prices	**Number Outstanding at December 31, 2011**	**Weighted-Average Remaining Term in Years**	**Weighted-Average Exercise Price**	**Number Exercisable at December 31, 2011**	**Weighted-Average Exercise Price**	**Aggregate Intrinsic Value**	**Number Unvested at December 31, 2011**	**Weighted-Average Exercise Price**
						(in millions)		
$7.78 - $11.89	582,050	0.6	$ 8.57	582,050	$ 8.57		-	$ -
19.37 - 27.84	1,219,409	3.7	24.31	827,557	23.99		391,852	25.00
39.07	202,235	6.2	39.07	-	-		202,235	39.07
	2,003,694	**3.1**	**$ 21.23**	**1,409,607**	**$ 17.62**	**$ 16.5**	**594,087**	**$ 29.79**

Restricted Shares

Restricted share grants typically vest in equal installments over a three or four year period from the grant date. Several grants vest in a single installment after a specific period. The weighted-average vesting period of unvested restricted shares at December 31, 2011 was 12 months. Transactions involving restricted shares under the terms of the LTSIP are summarized below:

	Restricted Shares Outstanding	Weighted-Average Price
Unvested balance at December 31, 2010	966,961	29.05
Granted	**465,653**	**38.50**
Vested	**(307,140)**	**28.82**
Forfeited	**(25,722)**	**35.71**
Unvested balance at December 31, 2011	**1,099,752**	**$ 32.78**

At the time of the Spin-off, all outstanding options and restricted stock were bifurcated. QEP assumed responsibility for expensing approximately 819,000 unvested Questar stock options with a weighted-average price of $11.43 per share and approximately 614,000 unvested Questar restricted shares with a weighted-average price of $13.73 per share. QEP will recognize expense in future periods for these unvested share-based awards.

Performance Share Units

During the year ended December 31, 2011, the Company granted its first performance based share units. Vesting is dependent upon the Company's total shareholder return compared to a group of its peers. The awards are denominated in share units but delivered in cash at the end of the performance period. The weighted-average vesting period of unvested performance shares at December 31, 2011, was 26 months. Transactions involving performance shares units under the terms of the LTCIP are summarized below:

	Performance Shares Outstanding	Weighted-Average Price
Unvest balance at January 1, 2011	-	$ -
Granted	116,074	39.07
Distributed	-	-
Forfeited	(800)	39.07
Unvested balance at December 31, 2011	**115,274**	**$ 39.07**

Note 11 – Employee Benefits

Defined Benefit Pension Plans and Other Postretirement Benefits

In association with the Spin-off, the Company established defined-benefit pension and postretirement medical plans providing coverage to approximately 190 of its employees. QEP only retained liability for active employees, while all of the retired employees remained participants in Questar's retirement plans. At the Spin-off, Questar transferred certain assets and liabilities from its defined-benefit pension and postretirement medical plans related to QEP employees into QEP's newly established plans. The transfer resulted in the establishment of liabilities of $54.9 million related to the unfunded portions of the defined-benefit pension plans and other postretirement benefits with corresponding amounts in AOCI.

Pension-plan benefits are based on the employee's age at retirement, years of service and highest earnings in a consecutive 72 semimonthly 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. The Company pays a portion of the costs of health-care benefits determined by an employee's years of service. The Company has capped its exposure to increasing medical care and life insurance costs by paying a fixed dollar monthly contribution toward these retiree benefits. The Company 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, 2011 and 2010, QEP's accumulated benefit obligation exceeded the fair value of plan assets as the plan is unfunded.

In 2011, the Company made contributions of $14.8 million to its funded pension plan. Although reported benefit obligations exceeded the fair value of pension and other postretirement plan assets at December 31, 2011, the Company monitors the funded status of its funded pension and other postretirement benefit plans to ensure that plan funds are sufficient to continue paying benefits. Contributions to the Company's funded plan increase plan assets while contributions to unfunded plans are used to fund current benefit payments. The Company expects to contribute approximately $6.3 million to its funded pension plan and approximately $1.3 million to its unfunded pension plan in 2012. The accumulated benefit obligation for all defined-benefit pension plans was $78.3 million and $57.4 million at December 31, 2011 and 2010.

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, 2011 and 2010, as well as the funded status of the plans and amounts recognized in the financial statements at December 31, 2011 and 2010:

	Pension benefits		Other postretirement benefits	
	2011	2010	**2011**	2010
	(in millions)			
Change in benefit obligation				
Benefit obligation at January 1,	**$ 78.0**	$ -	**$ 4.5**	$ -
Service cost	**2.9**	1.3	**0.1**	0.1
Interest cost	**4.5**	2.1	**0.3**	0.1
Change in plan assumptions	**19.6**	(1.1)	-	(0.1)
Transfer due to Spin-off	-	75.7	-	4.4
Benefit payments	**(0.2)**	-	-	-
Actuarial loss (gain)	**(0.7)**	-	**1.0**	-
Benefit obligation at December 31,	**$ 104.1**	$ 78.0	**$ 5.9**	$ 4.5
Change in plan assets				
Fair value of plan assets at January 1,	**$ 30.9**	$ -	**$ -**	$ -
Actual gain (loss) on plan assets	**(1.3)**	4.1	-	-
Company contributions to the plan	**14.8**	1.6	-	-
Benefit payments	**(0.2)**	-	-	-
Transfer due to Spin-off	-	25.2	-	-
Fair value of plan assets at December 31,	**44.2**	30.9	-	-
Underfunded status (current and long-term)	**$ (59.9)**	$ (47.1)	**$ (5.9)**	$ (4.5)
Amounts recognized in balance sheets				
Accounts payable and accrued expenses	**$ (1.3)**	$ -	**$ -**	$ -
Other long-term liabilities	**(58.6)**	(47.1)	**(5.9)**	(4.5)
Total amount recognized in balance sheet	**$ (59.9)**	$ (47.1)	**$ (5.9)**	$ (4.5)
Amounts recognized in accumulated other comprehensive income (AOCI)				
Net actuarial loss (gain)	**$ 18.6**	$ (4.2)	**$ 1.0**	$ (0.1)
Prior service cost	**42.6**	47.8	**3.8**	4.2
Total amount recognized in AOCI	**$ 61.2**	$ 43.6	**$ 4.8**	$ 4.1

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

	Pension benefits			Other postretirement benefits		
	2011	2010	2009	**2011**	2010	2009
	(in millions)					
Components of net periodic benefit cost						
Service cost	**$ 2.9**	$ 1.3	$ -	**$ 0.1**	$ 0.1	$ -
Interest cost	**4.5**	2.1	-	**0.3**	0.1	-
Expected return on plan assets	**(2.6)**	(1.1)	-	-	-	-
Amortization of prior service costs	**5.3**	2.6	-	**0.3**	0.2	-
Net periodic benefit cost	**$ 10.1**	$ 4.9	$ -	**$ 0.7**	$ 0.4	$ -
Components recognized in other comprehensive income						
Net loss (gain)	**$ 22.9**	$ (4.2)	$ -	**$ 1.0**	$ -	$ -
Prior service cost	-	50.4	-	-	4.3	-
Recognized prior service cost	**(5.3)**	(2.6)	-	**(0.3)**	(0.1)	-
Total amount recognized in other comprehensive income	**$ 17.6**	$ 43.6	$ -	**$ 0.7**	$ 4.2	$ -

The estimated portion of net actuarial loss and net prior service cost for the pension plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2012 is $6.0 million, of which $5.3 million represents amortization of prior service cost recognition and the remaining $0.7 million represents amortization of net actuarial losses. The estimated portion to be recognized in net periodic cost for other postretirement benefits from accumulated other comprehensive income in 2012 is $0.4 million due to amortization of prior service cost recognition.

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, 2011 and 2010:

	Pension benefits		Other postretirement benefits	
	2011	2010	**2010**	2009
Discount rate	**4.54%**	5.80%	**4.70%**	5.80%
Rate of increase in compensation	**3.60%**	3.60%	**n/a**	n/a

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 assumptions 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		
	2011	2010	2009	**2011**	2010	2009
Discount rate	**5.80%**	5.70%	n/a	**5.80%**	5.70%	n/a
Expected long-term return on plan assets	**7.50%**	7.50%	n/a	**n/a**	n/a	n/a
Rate of increase in compensation	**3.60%**	3.60%	n/a	**n/a**	n/a	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 2012. In measuring the other postretirement benefit obligation the following assumed health care cost trend rates were used:

	December 31,	
	2011	2010
Health care cost trend rate assumed for next year	**8.00%**	8.00%
Ultimate health care cost trend rate	**5.00%**	5.00%
Year rate reaches ultimate trend rate	**2014**	2013

Service costs and interest costs may be sensitive to changes in the health-care inflation rate. A 1% increase in the health-care inflation rate would increase the yearly service and interest costs and the accumulated postretirement benefit obligation by negligible amounts. A 1% decrease in the health-care inflation rate would decrease the yearly service cost and interest cost and the accumulated postretirement-benefit obligation by negligible amounts.

Plan Assets

The Company's Employee Benefits Committee (EBC) has oversight over investment of retirement-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 market foreign equity assets which were invested in a fund that holds a diversified portfolio of common stocks of corporations in developed foreign countries and emerging market foreign equity assets that were invested in a fund that holds a diversified portfolio of common stocks of corporations in 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 and Disclosures” 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 inputs for an asset. These 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.

	As of December 31, 2011				
	Level 1	Level 2	Level 3	Total	Percentage of total
	(in millions except percentages)				
Cash and short-term investments	$ -	$ -	$ -	$ -	-
Total domestic equity securities	-	-	17.6	17.6	40%
Foreign equity securities					
Developed market foreign equity securities	-	-	10.8	10.8	24%
Emerging market foreign equity securities	-	-	2.2	2.2	5%
Debt securities					
Investment grade intermediate term debt	-	-	6.9	6.9	16%
Investment grade long-term debt	-	-	6.7	6.7	15%
Total investments	$ -	$ -	$ 44.2	$ 44.2	100%

	As of December 31, 2010				
	Level 1	Level 2	Level 3	Total	Percentage of total
	(in millions except percentages)				
Cash and short-term investments	$ -	$ -	$ -	$ -	-
Total domestic equity securities	-	-	12.4	12.4	40%
Foreign equity securities					
Developed market foreign equity securities	-	-	7.8	7.8	25%
Emerging market foreign equity securities	-	-	1.6	1.6	5%
Debt securities					
Investment grade intermediate term debt	-	-	4.6	4.6	15%
Investment grade long-term debt	-	-	4.5	4.5	15%
Total investments	$ -	$ -	$ 30.9	$ 30.9	100%

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

	Year ended December 31,	
	2011	**2010**
	(in millions)	
Balance at January 1,	**$ 30.9**	$ -
Transfer due to Spin-off	-	25.2
Employer contributions	**14.8**	1.6
Unrealized gains and losses	**(1.3)**	4.1
Benefits paid	**(0.2)**	
Balance at December 31,	**$ 44.2**	$ 30.9

Expected Benefit Payments
As of December 31, 2011, the following future benefit payments are expected to be paid:

	Pension	Postretirement benefits
	(in millions)	
2012	$ 1.9	$ 0.1
2013	2.0	0.1
2014	2.9	0.2
2015	3.2	0.2
2016	4.1	0.3
2017 through 2021	38.1	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. The Company currently contributes an overall match of 100% of employees' contribution up to a maximum of 6% of their qualifying earnings. In addition, from time-to-time at the discretion of management, the Company may contribute a discretionary portion beyond the company match. The Company recognizes expense equal to its yearly contributions, which amounted to $6.2 million and $4.2 million during the years ended December 31, 2011 and 2010.

Note 12 – Operations by Line of Business

QEP's lines of business include gas and oil exploration and production (QEP Energy), midstream field services (QEP Field Services) and marketing (QEP Marketing and other). Line of business information is presented according to senior management's basis for evaluating performance including differences in the nature of products, services and regulation. Following is a summary of operations by line of business for the three years ended December 31, 2011:

	QEP Consolidated	Interco Transactions	QEP Energy	QEP Field Services	QEP Marketing & Other	QEP Resources
			(in millions)			
2011						
Revenues						
From unaffiliated customers	$ 3,159.2	$ -	$ 2,213.2	$ 369.3	$ 576.7	$ -
From affiliated customers	-	(676.4)	-	96.2	580.2	-
Total Revenues	3,159.2	(676.4)	2,213.2	465.5	1,156.9	-
Operating expenses						
Purchased gas and oil expense	1,077.1	(573.8)	506.4	-	1,144.5	-
Lease operating expense	145.2	(3.0)	148.2	-	-	-
Gathering, processing and other	107.3	-	-	106.0	1.3	-
Natural gas, oil and NGL transportation and other handling costs	102.2	(93.1)	186.0	9.3	-	-
General and administrative	123.2	(6.5)	98.4	29.2	2.1	-
Production and property taxes	105.4	-	99.1	6.1	0.2	-
Depreciation, depletion and amortization	765.4	-	707.2	55.7	2.5	-
Other operating expenses	228.9	-	228.9	-	-	-
Total Operating expenses	2,654.7	(676.4)	1,974.2	206.3	1,150.6	-
Net gain (loss) from asset sales	1.4	-	1.4	-	-	-
Operating income	505.9	-	240.4	259.2	6.3	-
Interest and other income	4.1	(98.7)	4.0	0.1	98.7	-
Income from unconsolidated affiliates	5.5	-	0.1	5.4	-	-
Loss on early extinguishment of debt	(0.7)	-	-	-	-	(0.7)
Interest expense	(90.0)	98.7	(81.9)	(13.6)	(93.2)	-
Income taxes	(154.4)	-	(57.9)	(93.4)	(3.4)	0.3
Income from continuing operations	270.4	-	104.7	157.7	8.4	(0.4)
Income from continuing operations attributable to noncontrolling interest	(3.2)	-	-	(3.2)	-	-
Income from continuing operations attributable to QEP	$ 267.2	$ -	$ 104.7	$ 154.5	$ 8.4	$ (0.4)
Identifiable assets	$ 7,442.7	$ -	$ 5,815.7	$ 1,312.7	$ 314.3	$ -
Investment in unconsolidated affiliates	42.2	-	-	42.2	-	-
Cash capital expenditures	1,431.1	-	1,295.5	130.1	5.5	-
Accrued capital expenditures	1,445.9	-	1,338.8	101.6	5.5	-
Goodwill	$ 59.5	$ -	$ 59.5	$ -	$ -	$ -

	QEP Consolidated	Interco Transactions	QEP Energy	QEP Field Services	QEP Marketing & Other	QEP Resources
			(in millions)			
2010						
Revenues [1]						
From unaffiliated customers	$ 2,300.6	$ -	$ 1,456.3	$ 245.5	$ 598.8	$ -
From affiliated customers	-	(573.4)	-	73.7	499.7	-
Total Revenues	2,300.6	(573.4)	1,456.3	319.2	1,098.5	-
Operating expenses						
Purchased gas and oil expense	589.3	(493.5)	-	-	1,082.8	-
Lease operating expense	125.0	(2.3)	127.3	-	-	-
Gathering, processing and other	83.2	-	-	82.1	1.1	-
Natural gas, oil and NGL transportation and other handling costs	54.2	(71.3)	125.5	-	-	-
General and administrative	107.2	(6.3)	78.0	31.6	3.9	-
Seperation costs	13.5	-	-	-	-	13.5
Production and property taxes	82.5	-	77.8	4.4	0.3	-
Depreciation, depletion and amortization	643.4	-	592.5	48.9	2.0	-
Other operating expenses	69.1	-	69.1	-	-	-
Total Operating expenses	1,767.4	(573.4)	1,070.2	167.0	1,090.1	13.5
Net gain (loss) from asset sales	12.1	-	13.7	(1.6)	-	-
Operating income	545.3	-	399.8	150.6	8.4	(13.5)
Interest and other income	2.3	(87.1)	2.1	0.1	87.2	-
Income from unconsolidated affiliates	3.0	-	0.2	2.8	-	-
Loss on early extinguishment of debt	(13.3)	-	-	-	-	(13.3)
Interest expense	(84.4)	87.1	(78.5)	(7.6)	(85.4)	-
Income tax expense	(167.0)	-	(119.7)	(51.9)	(3.5)	8.1
Income from continuing operations	285.9	-	203.9	94.0	6.7	(18.7)
Income from continuing operations attributable to noncontrolling interest	(2.9)	-	-	(2.9)	-	-
Income from continuing operations attributable to QEP	$ 283.0	$ -	$ 203.9	$ 91.1	$ 6.7	$ (18.7)
Identifiable assets	6,785.3	-	5,391.9	1,197.5	195.9	
Investment in unconsolidated affiliates	44.5	-	-	44.5	-	
Cash capital expenditures	1,469.0	-	1,205.0	262.1	1.9	
Accrued capital expenditures	1,485.9	-	1,215.8	268.2	1.9	
Goodwill	59.6	-	59.6	-	-	

	QEP Consolidated	Interco Transactions	QEP Energy	QEP Field Services	QEP Marketing & Other	QEP Resources
			(in millions)			
2009						
Revenues [1]						
From unaffiliated customers	$ 2,011.2	$ -	$ 1,356.0	$ 212.7	$ 442.5	$ -
From affiliated customers	-	(420.0)	-	51.9	368.1	-
Total Revenues	2,011.2	(420.0)	1,356.0	264.6	810.6	-
Operating expenses						
Purchased gas and oil expense	427.8	(362.8)	-	-	790.6	-
Lease operating expense	125.5	(2.0)	127.5	-	-	-
Gathering, processing and other	76.2	-	-	75.0	1.2	-
Natural gas, oil and NGL transportation and other handling costs	38.7	(50.0)	88.7	-	-	-
General and administrative	91.7	(5.2)	68.0	25.0	3.9	-
Seperation costs	-	-	-	-	-	-
Production and property taxes	62.9	-	58.3	4.6	-	-
Depreciation, depletion and amortization	559.1	-	512.8	44.3	2.0	-
Other operating expenses	45.3	-	45.3	-	-	-
Total Operating expenses	1,427.2	(420.0)	900.6	148.9	797.7	-
Net gain (loss) from asset sales	1.5	-	1.6	(0.1)	-	-
Operating income	585.5	-	457.0	115.6	12.9	-
Interest and other income	(185.1)	(70.7)	(185.7)	(0.2)	71.5	-
Income from unconsolidated affiliates	2.7	-	0.1	2.6	-	-
Loss on early extinguishment of debt	-	-	-	-	-	-
Interest expense	(70.1)	70.7	(63.9)	(6.0)	(70.9)	-
Income tax expense	(117.6)	-	(72.6)	(40.0)	(5.0)	-
Income from continuing operations	215.4	-	134.9	72.0	8.5	-
Income from continuing operations attributable to noncontrolling interest	(2.6)	-	-	(2.6)	-	-
Income from continuing operations attributable to QEP	$ 212.8	$ -	$ 134.9	$ 69.4	$ 8.5	$ -
Identifiable assets	5,828.9	-	4,633.0	929.2	266.7	
Investment in unconsolidated affiliates	43.9	-	-	43.9	-	
Cash capital expenditures	1,198.4	-	1,108.6	88.3	1.5	
Accrued capital expenditures	1,108.4	-	1,033.7	73.3	1.4	
Goodwill	60.1	-	60.1	-	-	

(1) Revenues for the years ended December 31, 2010 and 2009 were recast to reflect transportation and other handling costs as a separate line entitled “Natural gas, oil and NGL transportation and other handling costs” within operating expenses. See footnote 1, “Significant Accounting Policies” for additional information.

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Note 13 – Quarterly Financial Information (Unaudited)

Following is a summary of unaudited quarterly financial information:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
			(in millions)		
2011					
Revenues [1]	**$ 617.9**	**$ 808.1**	**$ 879.9**	**$ 853.3**	**$ 3,159.2**
Operating income	**137.1**	**168.9**	**183.4**	**16.5**	**505.9**
Income from continuing operations	**73.8**	**93.5**	**102.4**	**0.7**	**270.4**
Net income (loss) attributable to QEP	**73.2**	**92.8**	**101.5**	**(0.3)**	**267.2**
Per share information attributable to QEP					
Basic EPS attributable to QEP	**$ 0.42**	**$ 0.52**	**$ 0.58**	**$ (0.01)**	**$ 1.51**
Diluted EPS attributable to QEP	**0.41**	**0.52**	**0.57**	**-**	**1.50**
2010					
Revenues [1]	$ 592.1	$ 542.3	$ 578.3	$ 587.9	$ 2,300.6
Operating income	142.9	127.6	149.3	125.5	545.3
Income from continuing operations	78.7	69.5	71.9	65.8	285.9
Discontinued operations, net of tax	21.2	22.0	-	-	43.2
Net income attributable to QEP	99.3	90.8	71.1	65.0	326.2
Per share information attributable to QEP					
Basic EPS from continuing operations	$ 0.45	$ 0.39	$ 0.40	$ 0.37	$ 1.61
Basic EPS attributable to QEP	0.57	0.52	0.40	0.37	1.86
Diluted EPS from continuing operations	0.44	0.39	0.40	0.37	1.60
Diluted EPS attributable to QEP	0.56	0.51	0.40	0.37	1.84

[1] During the year ended December 31, 2011, QEP revised its reporting of transportation and handling costs which have been recast on the Consolidated Income Statement from revenues to "Natural gas, oil and NGL transportation and other handling costs" for all periods presented. See Note 1, "Summary of Significant Accounting Policies" for additional information. The following table presents prior periods presentation of revenues as previously disclosed:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2011	$ 596.2	$ 784.1	$ 852.4	n/a	n/a
2010	580.2	529.6	564.6	572.0	2,246.4

Note 14 – Supplemental Gas and Oil Information (Unaudited)

The Company is making the following supplemental disclosures of gas and oil 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 gas and oil exploration and development activities. All properties are located in the United States.

Capitalized Costs

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

	December 31,	
	2011	2010
	(in millions)	
Proved properties	$ 8,172.4	$ 6,874.3
Unproved properties	326.8	322.0
Proved properties	8,499.2	7,196.3
Accumulated depreciation, depletion and amortization	(3,339.2)	(2,454.4)
Net capitalized costs	$ 5,160.0	$ 4,741.9

Costs Incurred

The costs incurred in gas and oil exploration and development activities are displayed in the table below. Development costs incurred reflect accrued capital costs of $43.2 million and ARO expenses of $3.4 million in 2011. The costs incurred to advance the development of reserves that were classified as proved undeveloped were approximately $533.6 million in 2011, $434.2 million in 2010 and $216.1 million in 2009.

	Year Ended December 31,		
	2011	2010	2009
		(in millions)	
Property acquisitions			
Unproved	**$ 48.0**	$ 109.1	$ 215.1
Proved	**0.1**	0.2	6.4
Exploration (capitalized and expensed)	**36.5**	146.4	92.9
Development	**1,267.8**	988.8	741.1
Total costs incurred	**$ 1,352.4**	$ 1,244.5	$ 1,055.5

Results of Operations

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

	Year Ended December 31,		
	2011	2010	2009
		(in millions)	
Revenues	**$ 2,213.2**	$ 1,456.3	$ 1,356.0
Production costs	**433.3**	330.6	274.5
Exploration expenses	**10.5**	23.0	25.0
Depreciation, depletion and amortization	**707.2**	592.5	512.8
Abandonment and impairment	**218.4**	46.1	20.3
Total expenses	**1,369.4**	992.2	832.6
Income before income taxes	**843.8**	464.1	523.4
Income taxes	**(300.4)**	(171.8)	(183.2)
Results of operations from producing activities excluding allocated corporate overhead and interest expenses	**$ 543.4**	$ 292.3	$ 340.2

Estimated Quantities of Proved Gas and Oil Reserves

Estimates of proved gas and oil 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.

All of QEP Energy's proved undeveloped reserves at December 31, 2011, are scheduled to be developed within five years from the date such locations were initially disclosed as proved undeveloped reserves, except for 217 Bcfe located within the northern portion of the Company's Pinedale Anticline leasehold in western Wyoming. Long-term development of natural gas reserves in the PAPA 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 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.

	Natural Gas (Bcf)	Oil (Mbbl)	NGL (Mbbl)	Natural Gas Equivalents (Bcfe)
Proved reserves				
Balance at January 1, 2009	2,028.5	26,079.7	5,505.9	2,218.1
Revisions of previous estimates	(318.9)	2,237.3	1,115.4	(298.8)
Extensions and discoveries	982.4	3,610.7	1,761.0	1,014.6
Purchase of reserves in place	1.7	124.0	0.9	2.5
Sale of reserves in place	-	-	-	-
Production	(168.7)	(2,746.7)	(705.0)	(189.5)
Balance at December 31, 2009	2,525.0	29,305.0	7,678.2	2,746.9
Revisions of previous estimates	46.3	640.0	4,779.8	78.6
Extensions and discoveries	248.4	26,085.6	6,137.3	441.8
Purchase of reserves in place	0.2	-	-	0.2
Sale of reserves in place	(3.2)	(774.1)	-	(7.8)
Production	(203.8)	(2,979.8)	(1,225.8)	(229.0)
Balance at December 31, 2010	2,612.9	52,276.7	17,369.5	3,030.7
Revisions of previous estimates [1]	**(270.1)**	**1,794.0**	**39,290.5**	**(23.5)**
Extensions and discoveries [2]	**641.9**	**17,360.4**	**22,600.7**	**881.6**
Purchase of reserves in place	**1.9**	**17.0**	**12.0**	**2.1**
Sale of reserves in place	**(0.8)**	**(192.0)**	-	**(1.9)**
Production	**(236.4)**	**(3,741.3)**	**(2,715.6)**	**(275.2)**
Balance at December 31, 2011	**2,749.4**	**67,514.8**	**76,557.1**	**3,613.8**
Proved developed reserves				
Balance at January 1, 2009	1,128.1	19,466.7	4,071.9	1,269.4
Balance at December 31, 2009	1,178.7	22,428.0	4,919.2	1,342.8
Balance at December 31, 2010	1,404.8	25,115.6	9,342.9	1,611.5
Balance at December 31, 2011	**1,538.3**	**32,955.5**	**38,388.1**	**1,966.3**
Proved undeveloped reserves				
Balance at January 1, 2009	900.4	6,613.0	1,434.0	948.7
Balance at December 31, 2009	1,346.3	6,877.0	2,759.0	1,404.1
Balance at December 31, 2010	1,208.1	27,161.1	8,026.6	1,419.2
Balance at December 31, 2011	**1,211.1**	**34,559.3**	**38,169.0**	**1,647.5**

(1) Revisions of previous estimates 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 natural gas volumes of 209.8 Bcf, 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 natural gas reserve related to shrink of about 59.6 Bcf. The remaining performance related reduction in the natural 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.

(2) 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), Unita 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, 2010 and 2009, 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, 2011, 2010 and 2009 by applying prices, which were the simple average of the first-of-the-month prices for the 12-months of 2011, 2010 and 2009 with consideration of known contractual price changes. The prices used do not include any impact of QEP's commodity derivatives portfolio. The average price per Mcf used to calculate proved natural gas reserves was $3.46 in 2011, $3.85 in 2010, and $3.06 in 2009. The aggregate average price per barrel used to calculate proved oil reserves was $82.96 in 2011, $65.91 in 2010, and $49.32 in 2009. The aggregate average price per barrel used to calculate proved NGL reserves was $41.55 in 2011, $39.13 in 2010, and $31.15 in 2009. 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 $614.9 million in 2012, $788.8 million in 2013 and $757.7 million in 2014.

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 probably differ from those required to be used in these calculations.

- Future operating and capital costs will probably differ from those required to be used in these calculations.

- Future market conditions, government regulations and reservoir conditions 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,		
	2011	2010	2009
		(in millions)	
Future cash inflows	**$ 18,300.6**	$ 14,174.8	$ 9,419.3
Future production costs	**(4,276.1)**	(3,701.8)	(2,841.8)
Future development costs	**(3,250.0)**	(2,275.9)	(2,252.7)
Future income tax expenses	**(2,837.1)**	(1,957.6)	(674.0)
Future net cash flows	**7,937.4**	6,239.5	3,650.8
10% annual discount for estimated timing of net cash flows	**(4,411.8)**	(3,533.9)	(2,207.8)
Standardized measure of discounted future net cash flows	**$ 3,525.6**	$ 2,705.6	$ 1,443.0

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,		
	2011	2010	2009
		(in millions)	
Balance at January 1,	**$ 2,705.6**	$ 1,443.0	$ 2,001.9
Sales of gas, oil and NGL produced during the period, net of production costs	**(1,779.9)**	(1,125.7)	(1,081.5)
Net change in sales prices and in production (lifting) costs related to future production	**1,472.5**	1,775.8	(813.1)
Net change due to extensions, discoveries and improved recovery	**1,806.4**	789.1	1,291.6
Net change due to revisions of quantity estimates	**(48.2)**	140.4	(380.4)
Net change due to purchases and sales of reserves in place	**(7.9)**	(25.8)	6.4
Previously estimated development costs incurred during the period	**533.6**	434.2	216.1
Changes in estimated future development costs	**(1,110.4)**	(325.4)	(347.4)
Accretion of discount	**355.4**	170.9	256.4
Net change in income taxes	**(411.4)**	(582.4)	295.8
Other	**9.9**	11.5	(2.8)
Net change	**820.0**	1,262.6	(558.9)
Balance at December 31,	**$ 3,525.6**	$ 2,705.6	$ 1,443.0

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

On November 11, 2011 the Audit Committee of the Board of Directors of QEP Resources, Inc. (the “Company”) approved the engagement of PricewaterhouseCoopers LLP (“PWC”) as the Company’s independent registered public accounting firm for the year ending December 31, 2012.   PWC informed the Company that it completed the prospective client evaluation process on November 15, 2011. In connection with the selection of PWC, also on November 11, 2011, the Audit Committee informed Ernst & Young LLP (“E&Y”) that it will be dismissed as the Company’s independent registered public accounting firm no later than the date of the filing of the Company’s Form 10-K for the 2011 fiscal year. The decision to change auditors was the result of a request for proposal process that included the largest four public accounting firms.

During the years ended December 31, 2011, 2010 and 2009, and through February 24, 2012, neither the Company nor anyone on its behalf has consulted with PWC with respect to either (i) the application of accounting principles to a specified transaction, either completed or proposed, or the type of audit opinion that might be rendered on the Registrant’s consolidated financial statements, and neither written nor oral advice was provided to the Company that PWC concluded was an important factor considered by the Company in reaching a decision as to any accounting, auditing or financial reporting issue; (ii) any matter that was either the subject of disagreement (as defined in Item 304(a)(1)(iv) of Regulation S-K and the related instructions to Item 304 of Regulation S-K) or a reportable event (as defined by Item 304(a)(1)(v) of Regulation S-K).

The report of E&Y on the Company’s consolidated financial statements for the years ended December 31, 2010 and 2009 did not contain an adverse opinion or disclaimer of an opinion, and was not qualified or modified as to uncertainty, audit scope or accounting principles, except that the report includes an explanatory paragraph related to the Company’s adoption of ASC 810-10-65-1, “Noncontrolling Interests in Consolidated Financial Statements”, and SEC Release No. 33-8995, “Modernization of Oil and Gas Reporting.”

During the years ended December 31, 2011, 2010 and 2009, and through February 24, 2012, there were no disagreements (as defined in Item 304(a)(1)(iv) of Regulation S-K and the related instructions to Item 304 of Regulation S-K) with E&Y on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which disagreements, if not resolved to the satisfaction of E&Y, would have caused E&Y to make reference to the subject matter of the disagreement in its report on the consolidated financial statements for such year.

During the years ended December 31, 2011, 2010 and 2009, and through February 24, 2012, there were no reportable events (as defined in Item 304(a)(1)(v) of Regulation S-K).

The Company has provided E&Y with a copy of the above disclosures, and E&Y has furnished the Company with a letter addressed to the SEC stating it agrees with the statements made above. For a copy of E&Y's letter see Exhibit No. 16.1 filed to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on November 17, 2011.

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 Company's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) under the Securities Exchange Act of 1934, as amended, as of December 31, 2011. Based on such evaluation, such officers have concluded that, as of December 31, 2011, 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 specificed by the SEC's rules and forms and that information 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, 2011, 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

QEP's management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rule 13a-15(f). QEP Resources, Inc.'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, 2011, 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. Based on the assessment, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2011, based on those criteria. Management included in its assessment of internal control over financial reporting all consolidated entities.

Ernst & Young 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, 2011, which is included in Item 8. Financial Statements and Supplementary Data.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by Item 10 concerning QEP's directors and nominees for directors 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 15, 2012, which will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2011 (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.

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

The Company has a Business Ethics and Compliance Policy (Ethics Policy) that applies to all of its directors, officers (including its Chief Executive Officer and Chief Financial Officer) and employees. QEP has posted the Ethics Policy on its website, www.qepres.com. Any waiver of the Ethics Policy for executive officers must be approved only by the Company's Board of Directors. QEP will post on its website any amendments to or waivers of the Ethics Policy 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 ACCOUNTING 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. 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 May 18, 2010. (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.)
3.5	Certificate of Designations of Series A Junior Participating Preferred Stock of QEP Resources, Inc. (Incorporated by reference to Exhibit 2. of QEP Resources, Inc.'s Registration Statement on Form 8-A filed with the Securities and Exchange Commission on June 30, 2010.)

Exhibit No.	Description
4.1	Form of 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.)
4.2	Form of 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.)
4.3	Form of 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 1, 2008.)
4.4	Form of 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 1, 2008.)
4.5	Form of 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.)
4.6	Form of 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.)
4.7	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.)
4.8	Rights Agreement, dated as of June 30, 2010, between QEP Resources, Inc. and Wells Fargo Bank, N.A., which includes the Form of Right Certificate as Exhibit B and the Summary of Rights to Purchase Preferred Stock as Exhibit C (Incorporated by reference to Exhibit 1 of QEP Resources, Inc.'s Registration Statement on Form 8-A filed with the Securities and Exchange Commission on June 30, 2010), as amended by the First Amendment to Rights Agreement, dated as of February 14, 2012 (Incorporated by reference to Exhibit 4.1 of QEP Resources, Inc.'s Current Report on Form 8-K filed with the Securities and Exchange Commission on February 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 25, 2011.)
10.2	Senior Unsecured Bridge Loan Agreement, dated as of June 30, 2010, among QEP Resources, Inc, as borrower, Deutsche Bank AG Cayman Islands Branch, as administrative agent, Bank of America, N.A. and BMO Capital Markets Financing, Inc., as co-syndication agents, JPMorgan Chase Bank, N.A. and Wells Fargo Bank, N.A., as co-documentation agents, and the lenders party thereto. (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 July 1, 2010.)
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+	Amended and Restated Employment Agreement dated June 15, 2010 by and between QEP Resources, Inc., Questar Corporation and Charles B. Stanley (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 16, 2010.)
10.8+	Amended and Restated Employment Agreement dated June 15, 2010 by and between QEP Resources, Inc., Questar Corporation and Richard J. Doleshek (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 16, 2010.)

Exhibit No.	Description
10.9+	QEP Resources, Inc. 2010 Annual Management Incentive Plan II (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 16, 2010.)
10.10+	QEP Resources, Inc. 2010 Long-Term Cash Incentive Plan (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 16, 2010).
10.11+	QEP Resources, Inc. 2010 Long-Term Stock Incentive Plan (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.)
10.12+	QEP Resources, Inc. Executive Severance Compensation Plan (Incorporated by reference to Exhibit No. 10.10 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 16, 2010), as amended and restated by the QEP Resources, Inc. Executive Severance Compensation Plan (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 16, 2012.)
10.13+	QEP Resources, Inc. Deferred Compensation Wrap Plan (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 December 1, 2011.)
10.14+	QEP Resources, Inc. Supplemental Executive Retirement Plan (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.)
10.15+	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.)
10.16+	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.)
10.17+	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.)
10.18+	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.)
10.19+	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.)
10.20+	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.)
10.21+	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.)
10.22+	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.)
10.23+	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.)
12.1*	Ratio of earnings to fixed charges.
16.1	QEP Resources, Inc. Change in Registrant's Certifying Accountant. (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 November 17, 2011.)
21.1*	Subsidiaries of the Company.
23.1*	Consent of Independent Registered Public Accounting Firm.

Exhibit No.	Description
23.2*	Consent of Independent Petroleum Engineers and Geologists.
23.3*	Qualifications and Report of Independent Petroleum Engineers and Geologists.
24*	Power of Attorney
31.1*	Certification signed by Charles B. Stanley, QEP Resources, Inc. 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 and Treasurer, 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. President and Chief Executive Officer and Executive Vice President, Chief Financial Officer and Treasurer, respectively, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
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
\+ 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, 2011				
Allowance for bad debts	**$ 2.3**	**$ 0.2**	**$ (0.8)**	**$ 1.7**
Year ended December 31, 2010				
Allowance for bad debts	3.0	(0.3)	(0.4)	2.3
Year ended December 31, 2009				
Allowance for bad debts	2.7	0.4	(0.1)	3.0

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 the 24th day of February, 2012.

QEP RESOURCES, INC.
(Registrant)

By: /s/ C. B. Stanley
C. B. Stanley
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 the date indicated.

/s/ C. B. Stanley C. B. Stanley	President and Chief Executive Officer Director (Principal Executive Officer)
/s/ Richard J. Doleshek Richard J. Doleshek	Executive Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ B. Kurtis Watts B. Kurtis Watts	Vice President and Controller (Principal Accounting Officer)
*Keith O. Rattie	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
*C. B. Stanley	Director

February 24, 2012
Date

*By /s/ C. B. Stanley
C. B. Stanley, Attorney in Fact

Exhibit 12.1

QEP Resources, Inc.
Ratio of Earnings to Fixed Charges

	Year Ended December 31,		
	2011	2010	2009
	(dollars in millions)		
Earnings			
Income from continuing operations before income taxes and adjustment for income or loss from equity investees	**$ 422.0**	$ 458.3	$ 330.3
Add (deduct):			
Fixed charges	**95.7**	89.8	72.1
Distributed income from equity investees	**7.9**	2.4	1.1
Capitalized interest	**(3.0)**	(3.1)	-
Noncontrolling interest in pre-tax income of subsidiary that has not incurred fixed charges	**(3.2)**	(2.9)	(2.6)
Total earnings	**$ 519.4**	$ 544.5	$ 400.9
Fixed Charges			
Interest expense	**$ 90.0**	$ 84.4	$ 70.1
Capitalized interest	**3.0**	3.1	-
Estimate of the interest within rental expense	**2.7**	2.3	2.0
Total Fixed Charges	**$ 95.7**	$ 89.8	$ 72.1
Ratio of Earnings to Fixed Charges	**5.4**	6.1	5.6

For purposes of this presentation, earnings represent income from continuing operations before income taxes adjusted for fixed charges, earnings and distributions of equity investees. Income before income taxes includes QEP Resources' share of pretax earnings of equity investees. Fixed charges consist of total interest charges (expensed and capitalized), amortization of debt issuance costs and losses from reacquired debt, and the interest portion of rental expense estimated at 50%.

Exhibit 21.1

QEP Resources, Inc.
Subsidiaries

Name	State of Organization	Reference
QEP Energy Company	Texas	(1)
QEP Field Services Company	Utah	(1)
QEP Marketing Company	Utah	(1)
QESI	Utah	(1)
Uintah Basin Field Services, LLC	Delaware	(5)
Rendezvous Gas Services, LLC	Wyoming	(3)
Three Rivers Gathering, LLC	Delaware	(4)
Rendezvous Pipeline Company, LLC	Colorado	(2)
Perry Land Management Company, LLC	Oklahoma	(2)
Roden Participants, LTD	Texas	(7)
Clear Creek Storage Company, LLC	Utah	(6)

(1) 100% owned by QEP Resources, Inc.
(2) 100% owned by QEP Field Services Company
(3) 78% owned by QEP Field Services Company
(4) 50% owned by QEP Field Services Company
(5) 38% owned by QEP Field Services Company
(6) 100 % owned by QEP Marketing Company
(7) 14% owned by QEP Energy Company

Exhibit 23.1

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. and the effectiveness of internal control over financial reporting of QEP Resources, Inc. included in this Form 10-K for the year ended December 31, 2011.

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

Exhibit 23.2

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

FAX (303) 623-4258

621 SEVENTEENTH STREET SUITE 1550 DENVER, COLORADO 80293 TELEPHONE (303) 623-9147

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

As independent petroleum engineers, we hereby consent to the reference of our firm and the use of information contained in our 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 and 2011 and to the inclusion of our report dated February 1, 2012 as an exhibit to the Annual Report on Form 10-K. We further consent to the incorporation by reference thereof 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 24, 2012

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

February 1, 2012

QEP Energy Company
1050 Seventeenth Street, Suite 500
Denver, Colorado 80265

Gentlemen:

At your request, Ryder Scott Company (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, 2011. The subject properties are located in the States of Arkansas, Colorado, Kansas, Louisiana, Montana, North Dakota, New Mexico, 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 February 1, 2012 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, 2011.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2011, 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, 2011

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Remaining Reserves				
Oil/Condensate – Barrels	31,039,305	1,916,229	34,559,294	67,514,828
Plant Products – Barrels	36,805,527	1,582,498	38,169,030	76,557,055
Gas – MMCF	1,473,943	64,296	1,211,136	2,749,375
Income Data M$				
Future Gross Revenue	$ 8,825,852	$ 412,668	$ 7,960,080	$ 17,198,600
Deductions	2,042,611	118,897	4,262,596	6,424,104
Future Net Income (FNI)	$ 6,783,241	$ 293,771	$ 3,697,484	$ 10,774,496
Discounted FNI @ 10%	$ 3,742,425	$ 159,997	$ 883,427	$ 4,785,849

Liquid hydrocarbons are expressed in standard 42 gallon barrels. All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars (M$).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package Aries™ 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. Gas reserves account for approximately 52 percent and liquid hydrocarbon reserves account for the remaining 48 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income M$ As of December 31, 2011
Discount Rate Percent	Total Proved
5	$6,754,774
15	$3,655,641
20	$2,935,246
25	$2,442,175

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 Definitions” 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 included herein do not attribute 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. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves 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 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used 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, analogy or volumetric 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 and pressure data available through December, 2011 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by QEP or obtained from public data sources 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 included herein were estimated by the volumetric method. The volumetric analysis utilized pertinent well data furnished to Ryder Scott by QEP or which we have obtained from public data sources that were available through December, 2011. The data utilized from the analogues as well as well 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, 2011. 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	$96.19/Bbl	$82.96/Bbl
	NGL	WTI Cushing	$96.19/Bbl	$41.55/Bbl
	Gas	Henry Hub	$4.12/MMBTU	$3.46/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 by QEP 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, 2011. 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 inquires 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 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, 2011 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. [Seal]
Colorado P.E. License No. 23260
Vice President

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

\s\ James L. Baird
James L. Baird, P.E.
Colorado P.E. 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.

QEP Energy Company

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

SEC Parameters

As of

December 31, 2011

Jimmy D. Pittillo
QUALIFICATIONS

PROFESSIONAL EXPERIENCE

- Petroleum Engineer with 17 years diversified oil and gas engineering experience with major and independent exploration and production companies.
- QEP Resources (QEP) Chief Reservoir Engineer, and member QEP Reserves Review Committee, since 2011
- Over 7 years of oil and gas reserves estimating experience with QEP (13 years total)
- Reservoir engineering experience spanning domestic and international basins including Rocky Mountains, Mid-Continent, onshore Gulf Coast, Gulf of Mexico and offshore Indonesia

EDUCATIONAL BACKGROUND

Mississippi State University, Starkville, Mississippi
Bachelor of Science, Petroleum Engineering – December 1993

PROFESSIONAL LICENSES AND AFFILIATIONS

Society of Petroleum Engineers – Member 1990

Exhibit 24

POWER OF ATTORNEY

We, the undersigned directors of QEP Resources, Inc., hereby severally constitute C. 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 2011 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 2011 and any and all amendments to such Report.

Witness our hands on the respective dates set forth below.

Signature	Title	Date
/s/ Keith O. Rattie Keith O. Rattie	Chairman of the Board	02/14/12
/s/ C.B. Stanley C. B. Stanley	President and Chief Executive Officer	02/14/12
/s/ Phillip S. Baker Phillips S. Baker	Director	02/14/12
/s/ L. Richard Flury L. Richard Flury	Director	02/14/12
/s/ Robert E. McKee Robert E. McKee	Director	02/14/12
/s/ M. W. Scoggins M. W. Scoggins	Director	02/14/12
/s/ David A. Trice David A. Trice	Director	02/14/12

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, 2011;

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 we 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.

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 function):

   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 24, 2012	/s/ Charles B. Stanley
Date	Charles B. Stanley President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Richard J. Doleshek, certify that:

6. I have reviewed this report of QEP Resources, Inc. on Form 10-K for the period ended December 31, 2011;

7. 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;

8. 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;

9. 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 we have:

   (e) 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;

   (f) 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;

   (g) 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

   (h) 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.

10. 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 function):

   (c) 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

   (d) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 24, 2012	/s/ Richard J. Doleshek
Date	Richard J. Doleshek Executive Vice President, Chief Financial Officer and Treasurer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with this report of QEP Resources, Inc. (the Company) on Form 10-K for the period ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the Report), C. B. Stanley, President and Chief Executive Officer of the Company, and Richard J. Doleshek, Executive Vice President, Chief Financial Officer and Treasurer of the Company, each hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

QEP RESOURCES, INC.

February 24, 2012	/s/ C. B. Stanley
Date	C. B. Stanley President and Chief Executive Officer
February 24, 2012	/s/ Richard J. Doleshek
Date	Richard J. Doleshek Executive Vice President, Chief Financial Officer and Treasurer