QEP RESOURCES, INC.
Form 10-Q
October 30, 2012

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

FORM 10-Q

ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarter ended September 30, 2012

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ______ to ______

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 or organization	(Commission File Number)	(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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (Section 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No o

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 the definitions of “large accelerated filer,” “accelerated filer”, and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):

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

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

At September 30, 2012, there were 178,116,761 shares of the registrant's common stock, $0.01 par value, outstanding.

QEP Resources, Inc.
Form 10-Q for the Quarter Ended September 30, 2012

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS
QEP RESOURCES, INC.
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in millions, except per share amounts)			
REVENUES				
Natural gas sales	$170.3	$309.8	$470.4	$921.1
Oil sales	117.7	76.9	335.7	220.6
NGL sales	67.5	79.3	247.0	191.0
Gathering, processing and other	46.3	57.1	141.9	162.6
Purchased gas, oil and NGL sales	140.6	356.8	449.9	810.6
Total Revenues	542.4	879.9	1,644.9	2,305.9
OPERATING EXPENSES				
Purchased gas, oil and NGL expense	142.6	352.7	455.9	803.3
Lease operating expense	42.2	37.0	122.8	104.1
Natural gas, oil and NGL transportation and other handling costs	36.3	27.5	111.5	73.2
Gathering, processing and other	22.1	27.0	66.4	79.4
General and administrative	41.7	28.7	114.5	89.1
Production and property taxes	24.3	27.7	68.4	78.5
Depreciation, depletion and amortization	234.1	189.0	647.4	566.4
Exploration expenses	2.2	2.4	6.3	7.5
Abandonment and impairment	9.5	5.7	71.8	16.4
Total Operating Expenses	555.0	697.7	1,665.0	1,817.9
Net gain from asset sales	—	1.2	1.5	1.4
OPERATING (LOSS) INCOME	(12.6)	183.4	(18.6)	489.4
Realized and unrealized gains on derivative contracts (See Note 7)	36.1	—	334.7	—
Interest and other (loss) income	(0.2)	(0.7)	2.4	(0.5)
Income from unconsolidated affiliates	2.3	2.3	5.6	4.5
Loss from early extinguishment of debt	—	(0.7)	(0.6)	(0.7)
Interest expense	(30.0)	(22.8)	(82.9)	(67.0)
(LOSS) INCOME BEFORE INCOME TAXES	(4.4)	161.5	240.6	425.7
Income tax benefit (provision)	2.3	(59.1)	(86.5)	(156.0)
NET (LOSS) INCOME	(2.1)	102.4	154.1	269.7
Net income attributable to noncontrolling interest	(1.0)	(0.9)	(2.7)	(2.2)
NET (LOSS) INCOME ATTRIBUTABLE TO QEP	$(3.1)	$101.5	$151.4	$267.5
Earnings Per Common Share Attributable to QEP				
Basic total	$(0.02)	$0.58	$0.85	$1.52
Diluted total	$(0.02)	$0.57	$0.85	$1.50
Weighted-average common shares outstanding				
Used in basic calculation	177.9	176.6	177.6	176.5

Used in diluted calculation	177.9	178.5	178.6	178.5
Dividends per common share	$0.02	$0.02	$0.06	$0.06

See notes accompanying the condensed consolidated financial statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in millions)			
Net (loss) income	$(2.1)	$102.4	$154.1	$269.7
Other comprehensive (loss) income, net of tax:				
Reclassification of previously deferred derivative (gains) losses (1)	(42.1)	37.3	(133.8)	(13.0)
Pension and other postretirement plans adjustments:				
Amortization of net actuarial loss (2)	0.5	—	0.7	—
Amortization of prior service cost (3)	0.9	1.4	2.6	3.1
Total pension and other postretirement plans adjustments	1.4	1.4	3.3	3.1
Other comprehensive (loss) income	(40.7)	38.7	(130.5)	(9.9)
Comprehensive (loss) income	(42.8)	141.1	23.6	259.8
Comprehensive income attributable to noncontrolling interests	(1.0)	(0.9)	(2.7)	(2.2)
Comprehensive (loss) income attributable to QEP	$(43.8)	$140.2	$20.9	$257.6

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(1) Presented net of income tax benefit of $24.9 million and $79.2 million during the three and nine months ended September 30, 2012, respectively, and net of income tax expense of $22.1 million during the three months ended September 30, 2011 and income tax benefit of $7.7 million during the nine months ended September 30, 2011, respectively.

(2) Presented net of income tax expense of $0.2 million and $0.4 million during the three and nine months ended September 30, 2012, respectively.

(3) Presented net of income tax expense of $0.5 million and $1.6 million during three and nine months ended September 30, 2012, respectively, and net of income tax expense of $0.8 million and $1.9 million during the three and nine months ended September 30, 2011, respectively.

See notes accompanying the condensed consolidated financial statements.

QEP RESOURCES, INC.
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2012	December 31, 2011
ASSETS	(in millions)	
Current Assets		
Cash and cash equivalents	$—	$—
Accounts receivable, net	274.3	397.4
Fair value of derivative contracts	187.2	273.7
Inventories, at lower of average cost or market		
Gas, oil and NGL	14.0	16.2
Materials and supplies	94.9	87.6
Prepaid expenses and other	49.4	43.7
Total Current Assets	619.8	818.6
Property, Plant and Equipment (successful efforts method for gas and oil properties)		
Proved properties	9,882.4	8,172.4
Unproved properties	983.4	326.8
Midstream field services	1,605.2	1,463.6
Marketing and other	56.3	49.8
Total Property, Plant and Equipment	12,527.3	10,012.6
Less Accumulated Depreciation, Depletion and Amortization		
Exploration and production	3,977.6	3,339.2
Midstream field services	342.9	297.5
Marketing and other	16.9	14.6
Total Accumulated Depreciation, Depletion and Amortization	4,337.4	3,651.3
Net Property, Plant and Equipment	8,189.9	6,361.3
Investment in unconsolidated affiliates	41.7	42.2
Goodwill	59.5	59.5
Fair value of derivative contracts	35.2	123.5
Other noncurrent assets	50.0	37.6
TOTAL ASSETS	$8,996.1	$7,442.7
LIABILITIES AND EQUITY		
Current Liabilities		
Checks outstanding in excess of cash balances	$27.5	$29.4
Accounts payable and accrued expenses	464.6	457.3
Production and property taxes	56.3	40.0
Interest payable	23.7	24.4
Fair value of derivative contracts	2.7	1.3
Deferred income taxes	41.9	85.4
Total Current Liabilities	616.7	637.8
Long-term debt	3,180.7	1,679.4
Deferred income taxes	1,505.8	1,484.7
Asset retirement obligations	176.6	163.9
Fair value of derivative contracts	4.1	—
Other long-term liabilities	135.2	124.8
Commitments and contingencies		
EQUITY		

Common stock - par value $0.01 per share; 500.0 million shares authorized; 178.5 million and 177.2 million shares issued, respectively	1.8	1.8
Treasury stock - 0.4 million and 0.4 million shares, respectively	(11.6)	(13.1)
Additional paid-in capital	455.8	431.4
Retained earnings	2,805.6	2,673.5
Accumulated other comprehensive income	77.4	207.9
Total Common Shareholders' Equity	3,329.0	3,301.5
Noncontrolling interest	48.0	50.6
Total Equity	3,377.0	3,352.1
TOTAL LIABILITIES AND EQUITY	$8,996.1	$7,442.7

See notes accompanying the condensed consolidated financial statements.

QEP RESOURCES, INC.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30,	
	2012	2011
	(in millions)	
OPERATING ACTIVITIES		
Net income	$154.1	$269.7
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	647.4	566.4
Deferred income taxes	54.7	155.9
Abandonment and impairment	71.8	16.4
Share-based compensation	19.5	16.5
Amortization of debt issuance costs and discounts	3.7	2.4
Dry exploratory well expense	0.1	0.5
Net gain from asset sales	(1.5)	(1.4)
Income from unconsolidated affiliates	(5.6)	(4.5)
Distributions from unconsolidated affiliates and other	6.1	7.6
Non-cash loss on early extinguishment of debt	—	0.7
Unrealized gain on derivative contracts	(32.8)	(86.7)
Changes in operating assets and liabilities	54.5	12.2
Net Cash Provided by Operating Activities	972.0	955.7
INVESTING ACTIVITIES		
Property acquisitions	(1,400.3)	(40.7)
Property, plant and equipment, including dry exploratory well expense	(1,040.7)	(957.7)
Proceeds from disposition of assets	5.3	7.4
Net Cash Used in Investing Activities	(2,435.7)	(991.0)
FINANCING ACTIVITIES		
Checks outstanding in excess of cash balances	(1.9)	7.2
Long-term debt issued	1,450.0	—
Long-term debt issuance costs paid	(17.0)	(10.5)
Long-term debt repaid	(6.7)	(58.5)
Proceeds from credit facility	933.5	280.0
Repayments of credit facility	(876.0)	(170.0)
Other capital contributions	(4.2)	0.1
Dividends paid	(10.7)	(10.6)
Excess tax benefit on share-based compensation	2.0	1.5
Distribution from Questar	—	0.2
Distribution to noncontrolling interest	(5.3)	(4.1)
Net Cash Provided by Financing Activities	1,463.7	35.3
Change in cash and cash equivalents	—	—
Beginning cash and cash equivalents	—	—
Ending cash and cash equivalents	$—	$—
Supplemental Disclosures:		
Cash paid for interest	$81.9	$89.8
Cash paid (received) for income taxes	28.0	(7.2)
Non-cash investing activities		

Change in capital expenditure accrual balance	$97.5	$12.5

See notes accompanying the condensed consolidated financial statements.

QEP RESOURCES, INC.
NOTES ACCOMPANYING THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Note 1 – Nature of Business

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

- QEP Energy Company (QEP Energy) acquires, explores for, develops, and produces 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;
- QEP Marketing Company (QEP Marketing) markets affiliate and third-party natural gas and oil, and owns and operates an underground gas-storage reservoir.

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

Shares of QEP Resources' common stock trade on the New York Stock Exchange under the ticker symbol "QEP".

Note 2 – Basis of Presentation of Interim Consolidated Financial Statements

The interim condensed consolidated financial statements contain the accounts of QEP and its majority-owned or controlled subsidiaries. The condensed consolidated financial statements were prepared in accordance with United States Generally Accepted Accounting Principles (GAAP) and with the instructions for quarterly reports on Form 10-Q and Regulations S-X and S-K. All significant intercompany accounts and transactions have been eliminated in consolidation.

The condensed consolidated financial statements reflect all normal recurring adjustments and accruals that are, in the opinion of management, necessary for a fair statement of financial position and results of operations for the interim periods presented. Interim condensed consolidated financial statements do not include all of the information and notes required by GAAP for audited annual consolidated financial statements. These condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2011.

The preparation of the condensed consolidated financial statements and notes in conformity with GAAP requires that management make estimates and assumptions that affect revenues, expenses, assets and liabilities, and disclosure of contingent assets and liabilities. Actual results could differ from estimates. The results of operations for the three and nine months ended September 30, 2012, are not necessarily indicative of the results that may be expected for the year ending December 31, 2012.

De-designation of commodity derivative contracts

Effective January 1, 2012, QEP elected to discontinue hedge accounting prospectively for all of its derivative instruments. Accordingly, all realized and unrealized gains and losses will be recognized in earnings immediately each quarter as derivative contracts are settled and marked-to-market. For the three and nine months ended September 30, 2012, unrealized losses of $57.1 million and unrealized gains of $32.8 million were included in income that, prior to January 1, 2012, would have been deferred in Accumulated Other Comprehensive Income (AOCI) under hedge accounting. Refer to Note 7 – Derivative Contracts for additional information.

Transportation and other handling costs

In the fourth quarter of 2011, QEP revised its reporting of transportation and handling costs to reflect revenues in accordance with industry practice and GAAP. Transportation and handling costs, previously netted against revenues, were recast on the Condensed Consolidated Statement of Operations from “Revenues” to “Natural gas, oil and NGL transportation and other handling costs” for prior periods presented. The impact of this revision was immaterial to the accompanying financial statements and had no effect on income from continuing operations, net income, or earnings per share. The following table details the impact for the three and nine months ended September 30, 2011, on the Condensed Consolidated Statement of Operations.

	Three Months Ended September 30, 2011			Nine Months Ended September 30, 2011		
	As reported [(1)] (in millions)	As revised	Change	As reported [(1)] (in millions)	As revised	Change
REVENUES						
Natural gas sales	$266.7	$309.8	$43.1	$795.8	$921.1	$125.3
Oil sales	76.1	76.9	0.8	218.4	220.6	2.2
NGL sales	75.7	79.3	3.6	183.1	191.0	7.9
Gathering, processing and other	77.1	57.1	(20.0)	224.8	162.6	(62.2)
OPERATING EXPENSES						
Natural gas, oil and NGL transportation and other handling costs	—	27.5	27.5	—	73.2	73.2

(1) The “As reported” numbers reflect QEP Field Services NGL sales of $41.6 million and $115.3 million for the three and nine months ended September 30, 2011, which were reclassified from “Gathering, processing and other” into “NGL sales” for consistency with current period presentation. In its third quarter 2011 Form 10-Q, QEP reported “NGL sales” of $34.1 million and $67.8 million, and “Gathering, processing and other” of $118.7 million and $340.1 million for the three and nine months ended September 30, 2011, respectively. The QEP Field Services NGL reclassification is all within “Revenues” and has no effect on income from continuing operations, net income or earnings per share.

Impairment of oil and gas properties

Proved gas and oil properties are evaluated on a field-by-field basis for potential impairment. Impairment is indicated when a triggering event occurs and/or the sum of the estimated undiscounted future net cash flows of an evaluated asset is less than the asset’s carrying value. Triggering events could include, but are not limited to, an impairment of gas and oil reserves caused by mechanical problems, faster-than-expected decline of reserves, lease-ownership issues, other-than-temporary decline in natural gas, NGL and crude 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.

Unproved properties are evaluated on a specific-asset basis or in groups of similar assets, as applicable. The Company performs periodic assessments of individually significant unproved oil and gas 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' evaluation of the lease, and the remaining lease term.

During the three and nine months ended September 30, 2012, QEP recorded impairment charges of $7.3 million and $68.7 million on its oil and gas properties, respectively. Of the $68.7 million impairment charge in the nine months ended September 30, 2012, $49.3 million related to the non-cash, price-related impairment charges on proved properties incurred in the first half of 2012. The impairment charges were related to the reduced value of certain fields resulting from lower natural gas, crude oil and NGL prices and impairments of unproven leasehold acquisition costs. Of the $68.7 million impairment charge during the nine months ended September 30, 2012, $60.0 million was related to oil and gas properties in the Southern Region and $8.7 million was related to oil and gas properties in the Northern Region.

Natural gas, NGL and crude oil prices

Historically, field-level 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, domestic natural gas supply has grown faster than natural gas demand, driven by advances in drilling and completion technologies, including horizontal drilling and multi-stage hydraulic fracturing, which have allowed producers to extract increased quantities of natural gas from shale, tight sand formations, and other unconventional reservoirs. Increased natural gas and NGL supplies have resulted in downward pressure on natural gas and NGL prices, while growing U.S. supplies combined with concern about the global economy and other factors have created volatility in the price of crude oil. Changes in the market prices for natural gas, crude oil, and NGL directly impact many aspects of QEP's business, including its financial condition, revenues, results of operations, planned drilling activity and related capital expenditures, liquidity, rate of growth, costs of goods and services required to drill and complete wells, and may impact the carrying value of its oil and natural gas properties.

New accounting pronouncements

In May of 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs, which develops common measurement and disclosure requirements regarding an entity's fair value measurements and aligns GAAP and International Financial Reporting Standards. The amendments are required for interim and annual reporting periods beginning after December 15, 2011. The adoption of these requirements did not have a material impact on the financial statements of QEP.

In June of 2011, the FASB issued ASU No. 2011-05, Presentation of Comprehensive Income, 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 December of 2011, the FASB issued ASU 2011-11, Disclosures about Offsetting Assets and Liabilities, which enhances disclosure requirements regarding an entity's financial instruments and derivative instruments that are offset or subject to a master netting arrangement. This information about offsetting and related netting arrangements will enable users of financial statements to understand the effect of those arrangements on the entity's financial position, including the effect of rights of setoff. 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.

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

Note 3 - Acquisition

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

The Acquisition meets the definition of a business combination under ASC 805, Business Combinations, as it included proved properties. Pro-forma information has not been presented due to the immateriality of revenues and expenses related to the Acquisition during the periods presented. The results of operations from September 27 to September 30, 2012 from the assets purchased in the Acquisition are not included in the three and nine months ended September 30, 2012 Condensed Consolidated Statements of Operations. During the third quarter of 2012, QEP Energy recorded the acquisition on its Condensed Consolidated Balance Sheet; however, the final purchase price is subject to revision based on the final valuation work and settlement of post-closing adjustments. The following table presents a summary of the preliminary purchase accounting entries (in millions):

Consideration given:	
Cash paid at closing	$1,394.2
Amounts recognized for preliminary fair value of assets acquired and liabilities assumed:	
Proved properties	$707.6
Unproved properties	686.5
Asset retirement obligations	(0.6)
Other assets	0.7
Total fair value	$1,394.2

Note 4 – Earnings Per Share

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

Unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents are considered participating securities and are included in the computation of earnings per share pursuant to the two-class method. The Company’s unvested restricted stock awards contain non-forfeitable dividend rights and participate equally with common stock with respect to dividends issued or declared. However, the Company’s unvested restricted stock does not have a contractual obligation to share in losses of the Company. The Company’s unexercised stock options do not contain rights to dividends. Under the two-class method, the earnings used to determine basic earnings per common share are reduced by an amount allocated to participating securities. When the Company records a net loss, none of the loss is allocated to the participating securities since the securities are not obligated to share in Company losses. Use of the two-class method has an insignificant impact on the calculation of basic and diluted earnings per common share. During the three months ended September 30, 2012, 0.8 million shares were not included in diluted common shares outstanding as they were anti-dilutive due to QEP’s net loss position. There were no anti-dilutive shares during the nine months ended September 30, 2012, and during the three and nine months ended September 30, 2011.

A reconciliation of the components of basic and diluted shares used in the EPS calculation follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in millions)			
Weighted-average basic common shares outstanding	177.9	176.6	177.6	176.5
Potential number of shares issuable upon excercise of in-the-money stock options under the Long-term Stock Incentive Plan	—	1.9	1.0	2.0
Average diluted common shares outstanding	177.9	178.5	178.6	178.5

Note 5 – 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 assets 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.

The following is a reconciliation of the changes in the asset retirement obligation from January 1, 2012, to September 30, 2012, respectively:

	Asset Retirement Obligations 2012 (in millions)
ARO liability at January 1,	$163.9
Accretion	7.7
Liabilities incurred	5.2
Liabilities settled	(0.2)
ARO liability at September 30,	$176.6

Note 6 – Fair Value Measurements

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

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

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

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

The fair value of financial assets and liabilities at September 30, 2012, is shown in the table below:

	Fair Value Measurements September 30, 2012				
	Level 1	Level 2	Level 3	Netting Adjustments	Total
		(in millions)			
Financial Assets					
Commodity derivative instruments - short-term	$—	$199.4	$—	$(12.2)	$187.2
Commodity derivative instruments - long-term	—	38.2	—	(3.0)	$35.2
Total financial assets	$—	$237.6	$—	$(15.2)	$222.4
Financial Liabilities					
Commodity derivative instruments - short-term	$—	$12.3	$—	$(12.2)	$0.1
Interest rate swaps - short-term	—	2.6	—	—	$2.6
Commodity derivative instruments - long-term	—	3.0	—	(3.0)	$—
Interest rate swaps - long-term	—	4.1	—	—	$4.1
Total financial liabilities	$—	$22.0	$—	$(15.2)	$6.8

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

The change in the fair value of Level 3 commodity derivative instruments assets and liabilities for the nine months ended September 30, 2012, is shown below:

	Change in Level 3 Fair Value Measurements 2012
	(in millions)
Balance at January 1,	$—
Realized gains and losses	0.6
Unrealized gains and losses	3.8
Settlements	(0.6)
Transfers out of Level 3	(3.8)
Balance at September 30,	$—

The fair value of financial assets and liabilities at December 31, 2011, is shown in the table below:

	Fair Value Measurements December 31, 2011				
	Level 1	Level 2	Level 3	Netting Adjustments	Total
		(in millions)			
Financial Assets					
Commodity derivative instruments - short-term	$—	$284.1	$—	$(10.4)	$273.7
Commodity derivative instruments - long-term	—	123.5	—	—	$123.5
Total financial assets	$—	$407.6	$—	$(10.4)	$397.2
Financial Liabilities					
Commodity derivative instruments - short-term	$—	$11.7	$—	$(10.4)	$1.3
Commodity derivative instruments - long-term	—	—	—	—	$—
Total financial liabilities	$—	$11.7	$—	$(10.4)	$1.3

The following table discloses the fair value and related carrying amount of certain financial instruments not disclosed in other notes to the condensed consolidated financial statements in this quarterly report on Form 10-Q:

	Carrying Amount	Level 1 Fair Value	Carrying Amount	Level 1 Fair Value
	September 30, 2012		December 31, 2011	
	(in millions)			
Financial liabilities				
Checks outstanding in excess of cash balances	$27.5	$27.5	$29.4	$29.4
Long-term debt	$3,180.7	$3,330.4	$1,679.4	$1,754.9

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

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

Nonrecurring Fair Value Measurements

The provisions of the fair value measurement standard are also applied to the Company's nonrecurring, non-financial measurements. The Company utilizes fair value on a non-recurring basis to review its proved oil and gas properties for potential impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such property. During the nine months ended September 30, 2012 and the year ended December 31, 2011, the Company recorded impairments on certain oil and gas properties resulting in a write down of the associated carrying value to fair value. The fair value of the property was measured utilizing the income approach and utilizing inputs which are primarily based upon internally developed cash flow models. Given the unobservable nature of the inputs, proved oil and gas property impairments are considered Level 3 within the fair value hierarchy. During the nine months ended September 30, 2012, the Company recorded $49.3 million of impairments related to some of its proved properties. The proved properties were written down to their estimated fair values of $36.7 million, at the time of impairment.

Note 7 – Derivative Contracts

QEP has established policies and procedures for managing commodity price volatility through the use of derivative instruments. In the normal course of business, QEP uses commodity 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 gains from favorable price movements. The volume of production subject to commodity derivative instruments and the mix of the instruments are frequently evaluated and adjusted by management in response to changing market conditions. QEP may enter into commodity derivative contracts for up to 100% of forecasted production from proved reserves. In addition, QEP may enter into commodity derivative contracts on a portion of its extracted NGL volumes in its midstream business and a portion of its natural gas sales and purchases for marketing transactions. QEP does not enter into commodity derivative instruments for speculative purposes.

QEP uses commodity derivative instruments known as fixed-price swaps 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 commodity 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. Natural gas price derivative instruments are typically structured as fixed-price swaps at regional price indices. Oil price derivative instruments are typically structured as NYMEX fixed-price swaps based at Cushing, Oklahoma. NGL price derivative instruments are typically structured as Mont Belvieu, Texas fixed-price swaps.

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

Through December 31, 2011, QEP designated the majority 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, QEP elected to de-designate all of its natural gas, crude oil and NGL derivative contracts that were previously designated as cash flow hedges and discontinue hedge accounting prospectively. As a result of discontinuing hedge accounting, the mark-to-market values at December 31, 2011, were fixed in AOCI as of the de-designation date and are being reclassified into the Consolidated Statement of Operations as the transactions settle and affect earnings. At September 30, 2012, AOCI consisted of $182.9 million ($114.9 million after tax) of unrealized gains. QEP expects to reclassify into earnings from AOCI the fixed value related to de-designated natural gas, oil and NGL hedges over the remainder of 2012 and 2013. Currently, QEP recognizes all gains and losses from changes in the fair value of natural gas, oil and NGL derivative contracts immediately in earnings rather than deferring any such amounts in AOCI. All commodity derivative instruments are recorded on the Consolidated Balance Sheets as either assets or liabilities measured at their fair values and all realized and unrealized gains and losses from derivative instruments incurred after January 1, 2012, are presented in the Consolidated Statement of Operations in “Realized and unrealized gains on derivative contracts” below operating income.

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

QEP Energy Derivative Contracts

The following table sets forth QEP Energy's quantities and average prices for its commodity derivative contracts as of September 30, 2012:

Year	Type of Contract	Index	Total Volumes	Swaps Average price per unit	Collars Floor price	Ceiling price
			(in millions)			
Natural gas sales			(MMBtu)			
2012	Swap	NYMEX	19.3	$4.72		
2012	Swap	IFPEPL (1)	1.8	$4.70		
2012	Swap	IFNPCR (2)	22.1	$4.67		
2012	Swap	IFCNPTE (3)	2.8	$2.66		
2013	Swap	NYMEX	29.2	$3.68		
2013	Swap	IFNPCR (2)	65.7	$5.66		
Oil sales			(Bbls)			
2012	Swap	NYMEX WTI	1.3	$97.42		
2012	Collar	NYMEX WTI	0.4		$87.50	$115.36
2013	Swap	NYMEX WTI	5.1	$98.48		
2014	Swap	NYMEX WTI	1.8	$92.72		
NGL sales			(Gals)			
2012	Swap	Mt. Belvieu Ethane	3.9	$0.64		
2012	Swap	Mt. Belvieu Propane	5.8	$1.28		

(1) Inside FERC monthly settlement index for the Panhandle Eastern Pipeline Company.
(2) Inside FERC monthly settlement index for the Northwest Pipeline Corp. Rocky Mountains.
(3) Inside FERC monthly settlement index for Centerpoint East.

QEP Field Services Derivative Contracts

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 September 30, 2012:

Year	Type of Contract	Index	Total Volumes	Average Swap price per gallon
			(in millions)	
NGL sales			(Gals)	
2012	Swap	Mt. Belvieu Ethane	3.9	$0.64
2012	Swap	Mt. Belvieu Propane	1.9	$1.28

QEP Marketing Derivative Contracts

QEP Marketing enters into commodity derivative transactions to lock in a margin on natural gas volumes placed into storage and for marketing transactions in which QEP Marketing is required to sell gas volumes at a fixed price. The following table sets forth QEP Marketing's volumes and swap prices for its commodity derivative contracts as of September 30, 2012:

Year	Type of Contract	Index	Total Volumes	Average Swap price per MMBtu
			(in millions)	
Natural gas sales			(MMBtu)	
2012	Swap	IFNPCR (1)	2.1	$3.93
2013	Swap	IFNPCR (1)	3.1	$3.77
Natural gas purchases			(MMBtu)	
2012	Swap	IFNPCR (1)	1.5	$2.76
2013	Swap	IFNPCR (1)	0.1	$2.59

(1) Inside FERC monthly settlement index for the Northwest Pipeline Corp. Rocky Mountains.

QEP Resources Derivative Contracts

In the second quarter of 2012, QEP Resources entered into interest rate swap agreements to effectively lock in a fixed interest rate on debt outstanding under its Term Loan.

The following table sets forth QEP Resources' notional amounts and interest rates for its interest rate swaps outstanding as of September 30, 2012:

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

QEP Derivative Financial Statement Presentation

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

	Balance Sheet line item	Gross asset derivative instruments fair value		Gross liability derivative instruments fair value	
		September 30, 2012	December 31, 2011	September 30, 2012	December 31, 2011
		(in millions)		(in millions)	
Current:					
Commodity	Fair value of derivative contracts	$199.4	$284.1	$12.3	$11.7
Interest rate swaps	Fair value of derivative contracts	—	—	2.6	—
Long-term:					
Commodity	Fair value of derivative contracts	38.2	123.5	3.0	—
Interest rate swaps	Fair value of derivative contracts	—	—	4.1	—
Total derivative instruments		$237.6	$407.6	$22.0	$11.7

The effects and location of the change in fair value and settlement of QEP's derivative contracts on the Condensed Consolidated Statements of Operations are summarized in the following tables:

Derivative instruments not designated as cash flow hedges	Location of gain (loss) recognized in earnings	Three Months Ended September 30, 2012	2011	Nine Months Ended September 30, 2012	2011
		(in millions)			
Realized gain (loss) on commodity derivative contracts					
QEP Energy					
Natural gas derivative contracts		$86.2	$(27.9)	$283.8	$(86.7)
Oil derivative contracts		2.7	—	2.2	—
NGL derivative contracts		3.4	—	6.5	—
QEP Field Services					
NGL derivative contracts		1.9	—	6.3	—
QEP Marketing					
Natural gas derivative contracts		(0.4)	—	3.7	—
Total realized gain (loss) on commodity derivative contracts		93.8	(27.9)	302.5	(86.7)
Unrealized gain (loss) on commodity derivative contracts					
QEP Energy					
Natural gas derivative contracts		(50.6)	27.9	3.3	86.7
Oil derivative contracts		4.1	—	31.2	—
NGL derivative contracts		(4.4)	—	3.4	—
QEP Field Services					
NGL derivative contracts		(2.5)	—	2.0	—
QEP Marketing					
Natural gas derivative contracts		(1.4)	—	(0.5)	—
Total unrealized (loss) gain on commodity derivative contracts		(54.8)	27.9	39.4	86.7
Total realized and unrealized gain on commodity derivative contracts		$39.0	$—	$341.9	$—
Realized gain (loss) on interest rate swaps					
Realized loss on interest rate swaps		$(0.6)	$—	$(0.6)	$—
Unrealized gain (loss) on interest rate swaps					
Unrealized loss on interest rate swaps		(2.3)	—	(6.6)	—
Total realized and unrealized loss on interest rate swaps		$(2.9)	$—	$(7.2)	$—
Grand Total	Realized and unrealized gains on derivative contracts	$36.1	$—	$334.7	$—

Derivative instruments classified as cash flow hedges	Location of gain (loss) recognized in earnings	Three Months Ended September 30,		Nine Months Ended September 30,	
		2012	2011	2012	2011
Commodity derivatives		(in millions)			
Gain on derivative instruments for the effective portion of hedge recognized in AOCI	Accumulated other comprehensive income	$—	$129.6	$—	$191.1
Gain reclassified from AOCI into income for effective portion of hedge	Natural gas sales	—	71.6	—	209.1
Gain reclassified from AOCI into income for effective portion of hedge	Oil sales	—	0.9	—	1.0
Gain reclassified from AOCI into income for effective portion of hedge	NGL sales	—	(0.3)	—	(0.3)
Gain reclassified from AOCI into income for effective portion of hedge	Marketing sales	—	—	—	—
Gain reclassified from AOCI into income for effective portion of hedge	Marketing purchases	—	0.4	—	4.3
Gain recognized in income for the ineffective portion of hedges	Interest and other income	—	(2.7)	—	(2.6)

The Company estimates that derivative contracts that were outstanding in AOCI at September 30, 2012, having a fixed fair value of $97.7 million, will be settled and reclassified from AOCI to the Condensed Consolidated Statements of Operations during the next twelve months.

Note 8 – Restructuring Costs

During the first quarter 2012, QEP began incurring costs related to the closure of its Oklahoma City office and the subsequent consolidation of its Southern Region operations into a single regional office located in Tulsa. The creation of one office for QEP's Southern Region is intended to increase regional efficiency, team-based collaboration and organizational productivity over the long term. During the third quarter of 2012, QEP incurred additional restructuring and reorganization costs related to consolidating various corporate and accounting functions to the Denver corporate headquarters. As part of the reorganization, QEP will incur costs associated with the severance, retention and relocation of employees and other exit costs associated with the termination of operating leases arising from office space that will no longer be utilized by the Company. The majority of the restructuring costs will be incurred during the remainder of 2012 and in 2013.

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

	QEP Energy	QEP Field Services	QEP Marketing	Total
Restructuring costs expected to be incurred	(in millions)			
One-time termination benefits	$3.4	$—	$0.3	$3.7
Retention & relocation expense	5.5	0.2	0.2	5.9
Lease termination costs	0.6	—	—	0.6
Total restructuring costs expected to be incurred	$9.5	$0.2	$0.5	$10.2
Total restructuring costs recognized in income during the current period				
During the three months ended September 30, 2012				
One-time termination benefits	$0.2	$—	$—	$0.2
Retention & relocation expense	—	—	—	—
Lease termination costs	—	—	—	—
Total restructuring costs incurred for the three months ended September 30, 2012	$0.2	$—	$—	$0.2
During the nine months ended September 30, 2012				
One-time termination benefits	$2.1	$—	$—	$2.1
Retention & relocation expense	3.2	—	—	3.2
Lease termination costs	—	—	—	—
Total restructuring costs incurred for the nine months ended September 30, 2012	$5.3	$—	$—	$5.3

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

	QEP Energy	QEP Field Services	QEP Marketing	Total
	(in millions)			
Balance at December 31, 2011	$—	$—	$—	$—
Costs incurred and charged to expense	5.3	—	—	5.3
Costs paid or otherwise settled	(5.1)	—	—	(5.1)
Balance at September 30, 2012	$0.2	—	—	$0.2

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Note 9 – 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:

	September 30, 2012	December 31, 2011
	(in millions)	
Revolving Credit Facility due 2016	$664.0	$606.5
Term Loan due 2017	300.0	—
6.05% Senior Notes due 2016	176.8	176.8
6.80% Senior Notes due 2018	134.0	138.6
6.80% Senior Notes due 2020	136.0	138.0
6.875% Senior Notes due 2021	625.0	625.0
5.375% Senior Notes due 2022	500.0	—
5.25% Senior Notes due 2023	650.0	—
Total principal amount of debt	3,185.8	1,684.9
Less unamortized discount	(5.1)	(5.5)
Total long-term debt outstanding	$3,180.7	$1,679.4

Of the total debt outstanding on September 30, 2012, the revolving credit facility due August 25, 2016, the Term Loan due April 18, 2017, and the 6.05% Senior Notes due September 1, 2016, will mature within the next five years.

Credit Facility

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

During the nine months ended September 30, 2012, QEP's weighted-average interest rate on borrowings from its Credit Facility was 2.05%. At September 30, 2012 and December 31, 2011, QEP was in compliance with the covenants under the credit agreement. At September 30, 2012, there was $664.0 million outstanding and QEP had $4.1 million in letters of credit outstanding under the Credit Facility.

Term Loan

During the second quarter of 2012, QEP entered into a $300.0 million senior, unsecured term loan agreement (Term Loan) with a group of financial institutions. The Term Loan provides for borrowings at short-term interest rates and contains covenants, restrictions and interest rates that are substantially the same as the Company's Credit Facility. The Term Loan matures in April 2017, and the maturity date may be extended one year with the agreement of the lenders. The proceeds from the Term Loan were used to pay down the Credit Facility and for general corporate purposes. During the nine months ended September 30, 2012, QEP's weighted-average interest rate on borrowings from the Term Loan was 2.02%. At September 30, 2012, QEP was in compliance with the covenants under the Term Loan credit agreement.

Senior Notes

During the third quarter of 2012, QEP completed a public offering of $650.0 million in aggregate principal amount of 5.25% senior notes due in May 2023 (2023 Senior Notes). The 2023 Senior Notes were issued at face value. Interest on the 2023 Senior Notes will be paid semi-annually, in May and November of each year. The estimated net proceeds of $640.8 million were used to fund a portion of the Acquisition, as described in Note 3 - Acquisition. The estimated costs associated with the offering were $9.2 million and were deferred and are being amortized over the life of the notes. The amortization expense related to all of the Company's deferred finance costs is included in “Interest expense” on the Condensed Consolidated Statement of Operations.

During the second quarter of 2012, QEP repurchased $6.7 million of its senior notes outstanding. QEP recognized a loss on extinguishment of debt from those repurchases and associated write-offs of debt issuance costs, discounts and premiums paid of $0.6 million.

During the first quarter of 2012, QEP completed a public offering of $500.0 million in aggregate principal amount of 5.375% senior notes due in October 2022 (2022 Senior Notes). The 2022 Senior Notes were issued at face value. Interest on the 2022 Senior Notes will be paid semi-annually, in April and October of each year. The net proceeds of $493.1 million were used to repay indebtedness under QEP's Credit Facility. The finance costs associated with the offering were $6.9 million and were deferred and are being amortized over the life of the notes.

At September 30, 2012, the Company had $2,221.8 million principal amount of senior notes outstanding with maturities ranging from September 2016 to May 2023 and coupons ranging from 5.25% to 6.875%. The senior notes pay interest semi-annually, are unsecured senior obligations and rank equally with all of our other existing and future unsecured and senior obligations. QEP may redeem some or all of its senior notes at any time before their maturity at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption. The indenture governing QEP’s senior notes contains customary events of default and covenants that may limit QEP’s ability to, among other things, place liens on its property or assets.

Note 10 – Contingencies

QEP is involved in various commercial and regulatory claims, 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 effect on the Company's financial position, results of operations or cash flows, except with regard to cases discussed below where management cannot determine at this time whether they will have a material effect. In accordance with ASC 450, Contingencies, an accrual is recorded for a loss contingency when its occurrence is probable and damages can be reasonably estimated based on the anticipated most likely outcome or the minimum amount within a range of possible outcomes. QEP's estimates are based on information known about the claims, and experience in contesting, litigating and settling similar claims. Disclosures are also provided for reasonably possible losses that could have a material effect on the Company's financial position, results of operations or cash flows. The following discussion describes the nature of QEP's major loss contingencies.

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) alleged that QEP Field Services (f/k/a Questar Gas Management) violated the Clean Air Act (CAA) and sought substantial penalties and a permanent injunction involving the manner of operation of five compressor stations located in the Uinta Basin of eastern Utah. On May 16, 2012, QEP Field Services settled this matter and the parties executed a consent decree which was subsequently approved by court order. The civil penalty paid to the government during the third quarter of 2012 was $3.7 million. A contribution of $0.4 million will be payable to a non-profit corporation or trust to be created by the Ute Indian Tribe of the Uintah and Ouray Reservation for the implementation of environmental programs for the benefit of Tribal members. The settlement also requires the Company to reduce its emissions by removing certain equipment, installing additional pollution controls and replacing the natural gas powered instrument control systems with compressed air control systems, all of which will require capital expenditures of approximately $2.4 million, of which $0.8 million had been spent as of September 30, 2012. QEP Field Services will have continuing operational compliance obligations under the consent decree at the affected facilities.

Litigation

Chieftain Royalty Company v. QEP Energy Company, Case No CJ2011-1, U. S. District Court for Oklahoma. This is a class action filed by two royalty owners on behalf of all QEP Energy royalty owners in the state of Oklahoma since 1988, asserting various claims for damages related to royalty valuation on all of QEP's Oklahoma wells. These claims include breach of contract, breach of fiduciary duty, fraud, unjust enrichment, tortious breach of contract, conspiracy, and conversion, based generally on asserted improper deduction of post-production costs. The court has certified the class as to the breach of contract, breach of fiduciary duty and unjust enrichment claims. Because this case involves complex legal issues and uncertainties, a large class of plaintiffs and a large number of producing properties and wells, and because the proceedings are in the early stages, with substantive discovery yet to be conducted, the Company is unable to estimate a reasonably possible loss or range of loss. Although the plaintiff class has not made a formal demand, based upon the class allegations, we believe the class may seek damages in excess of $200 million. QEP Energy is still evaluating the claims, but believes that it has properly valued and paid royalty under Oklahoma law and will vigorously defend this case.

Questar Gas Company v. QEP Field Services Company, Civil No. 120902969, Third Judicial District Court, State of Utah. QEP Field Services' former affiliate Questar Gas Company (QGC) filed this complaint in state court in Utah on May 1, 2012, asserting claims for breach of contract, breach of implied covenant of good faith and fair dealing, for an accounting and declaratory judgment related to a 1993 gathering agreement (1993 Agreement) entered when the parties were affiliates. Under the 1993 Agreement, QEP Field Services provides gathering services for producing properties developed by former affiliate Wexpro Company on behalf of QGC's utility ratepayers. The core dispute pertains to the annual calculation of the gathering rate, which is based on a cost of service concept expressed in the 1993 Agreement and in a 1998 amendment. The annual gathering rate has been calculated in the same manner under the contract since it was amended in 1998, without any prior objection or challenge by QGC. Specific monetary damages are not asserted. Also, on May 1, 2012, QEP Field Services Company filed a legal action against Questar Gas entitled QEP Field Services Company v. Questar Gas Company, in the Second District Court in Denver County, Colorado, seeking declaratory judgment relating to its gathering service and charges under the same agreement.

Note 11 – Share-Based Compensation

QEP issues stock options and restricted shares under its Long-Term Stock Incentive Plan (LTSIP) and awards performance-based share units under its Cash Incentive Plan (CIP) to certain officers, employees, and non-employee directors. QEP recognizes expense over time as the stock options, restricted shares, and performance-based share units vest. Deferred share-based compensation is included in additional paid-in capital in the Condensed Consolidated Balance Sheets. There were 13.1 million shares available for future grants under the LTSIP at September 30, 2012. Share-based compensation expense is recognized in “General and administrative” on the Condensed Consolidated Statements of Operations. During the three and nine months ended September 30, 2012, QEP recognized $7.2 million and $19.5 million, respectively, in total compensation expense related to share-based compensation compared to $5.7 million and $16.5 million during the three and nine months ended September 30, 2011. The increase in share-based compensation recognized in 2012 compared to 2011 was due to increased restricted shares and options granted in late 2011 and throughout 2012.

Stock Options

QEP uses the Black-Scholes-Merton mathematical model to estimate 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 is intended for measuring 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:

	Stock Option Variables Nine Months Ended September 30, 2012	
Fair value of options at grant date	$14.29	
Risk-free interest rate	0.81	%
Expected price volatility	55.9	%
Expected dividend yield	0.26	%
Expected life in years	5.0	

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

	Options Outstanding	Weighted-Average Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
		(per share)	(in years)	(in millions)
Outstanding at December 31, 2011	2,003,694	$21.23		
Granted	301,035	30.76		
Exercised	(336,675)	9.21		
Forfeited	—	—	—	
Outstanding at September 30, 2012	1,968,054	$24.74	3.4	$15.1
Options Exercisable at September 30, 2012	1,505,051	$22.38	2.6	$14.6
Unvested Options at September 30, 2012	463,003	$32.43	5.9	$0.2

The total intrinsic value (the difference between the market price at the exercise date and the exercise price) of options exercised was $7.1 million and $2.7 million during the nine months ended September 30, 2012 and 2011, respectively. As of September 30, 2012, $3.6 million of unrecognized compensation cost related to stock options granted under the LTSIP is expected to be recognized over a weighted-average period of 2.2 years.

Restricted Shares

Restricted share grants typically vest in equal installments over a three or four-year period from the grant date. The total fair value of restricted stock that vested during the nine months ended September 30, 2012 and 2011, was $16.6 million and $11.5 million, respectively. The weighted average grant-date fair value of restricted stock was $30.59 per share and $39.26 per share for the nine months ended September 30, 2012 and 2011, respectively. As of September 30, 2012, $21.1 million of unrecognized compensation cost related to restricted shares granted under the LTSIP is expected to be recognized over a weighted-average vesting period of 2.2 years.

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

	Restricted Shares Outstanding	Weighted-Average Price
		(per share)
Unvested balance at December 31, 2011	1,099,752	$32.80
Granted	778,780	30.59
Vested	(538,668)	31.88
Forfeited	(61,502)	32.70
Unvested balance at September 30, 2012	1,278,362	$31.85

Performance Share Units

Cash payouts are dependent upon the Company’s total shareholder return compared to a group of its peers over a three-year period. The awards are denominated in share units but delivered in cash at the end of the performance period. The weighted average grant-date fair value of the performance share units was $30.90 per share and $39.07 per share for the nine months ended September 30, 2012 and 2011, respectively. As of September 30, 2012, $6.2 million of unrecognized compensation cost, or the fair market value, related to performance shares granted under the CIP is expected to be recognized over a weighted-average vesting period of 2.1 years.

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

	Performance Share Units Outstanding	Weighted-Average Price
Unvested balance at December 31, 2011	115,274	$39.07
Granted	179,304	30.90
Vested	—	—
Forfeited	(12,713)	35.69
Unvested balance at September 30, 2012	281,865	$34.03

Note 12 – Employee Benefits

The Company has a funded qualified defined benefit pension plan and an unfunded supplemental defined benefit pension plan. The Company also has unfunded postretirement benefit plans that provide certain health care and life insurance benefits for certain retired employees. During the nine months ended September 30, 2012, the Company made contributions of $4.9 million to its funded pension plan, and $1.0 million to its unfunded pension plan. Contributions to funded plans increase plan assets while contributions to unfunded plans are used to fund current benefit payments. During the remainder of 2012, the Company expects to contribute approximately $0.7 million to its funded pension plans, and approximately $0.3 million to its unfunded pension plans. In July 2012, Congress passed the Moving Ahead for Progress in the 21st Century Act, which included pension funding stabilization provisions. The measure, which is designed to stabilize the discount rate used to determine funding requirements from the effects of interest rate volatility, may reduce the Company's United States Pension Plan contributions during the remainder of 2012 from the planned amounts.

The following table sets forth the Company's pension and postretirement benefits net period benefit costs:

	Pension			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in millions)			
Service cost	$1.1	$0.7	$3.0	$2.1
Interest cost	1.3	1.2	3.7	3.4
Expected return on plan assets	(0.9)	(0.7)	(2.7)	(1.9)
Amortization of prior service costs	1.3	1.4	3.9	4.0
Amortization of actuarial loss	0.6	—	1.0	—
Periodic expense	$3.4	$2.6	$8.9	$7.6

	Postretirement benefits			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in millions)			
Service cost	$0.1	$0.1	$0.1	$0.1
Interest cost	—	—	0.2	0.2
Expected return on plan assets	—	—	—	—
Amortization of prior service costs	0.1	0.1	0.3	0.3

Recognized net actuarial loss	—	—	—	—
Periodic expense	$0.2	$0.2	$0.6	$0.6

Note 13 – Operations by Line of Business

QEP's lines of business include natural gas and oil exploration and production (QEP Energy), midstream field services (QEP Field Services) and marketing (QEP Marketing and other). The lines of business are managed separately and therefore the financial information is presented separately due to the distinct differences in the nature of operations of each line of business, among other factors.

The following table is a summary of operating results for the three months ended September 30, 2012, by line of business:

	QEP Energy	QEP Field Services	QEP Marketing & Other	Eliminations	QEP Consolidated
	(in millions)				
Revenues [1]					
From unaffiliated customers	$374.0	$77.9	$90.5	$—	$542.4
From affiliated customers	—	31.8	145.8	(177.6)	—
Total Revenues	374.0	109.7	236.3	(177.6)	542.4
Operating expenses					
Purchased gas, oil and NGL expense	45.9	4.9	236.7	(144.9)	142.6
Lease operating expense	43.1	—	—	(0.9)	42.2
Natural gas, oil and NGL transportation and other handling costs	59.8	6.9	—	(30.4)	36.3
Gathering, processing and other	—	21.8	0.1	0.2	22.1
General and administrative	32.2	10.6	0.5	(1.6)	41.7
Production and property taxes	22.5	1.7	0.1	—	24.3
Depreciation, depletion and amortization	217.4	15.8	0.9	—	234.1
Other operating expenses	11.7	—	—	—	11.7
Total operating expenses	432.6	61.7	238.3	(177.6)	555.0
Operating (loss) income [2]	(58.6)	48.0	(2.0)	—	(12.6)
Realized and unrealized gains (losses) on derivative contracts	41.4	(0.6)	(4.7)	—	36.1
Interest and other income	(0.2)	—	28.4	(28.4)	(0.2)
Income from unconsolidated affiliates	—	2.3	—	—	2.3
Interest expense	(24.1)	(3.5)	(30.8)	28.4	(30.0)
(Loss) income before income taxes	(41.5)	46.2	(9.1)	—	(4.4)
Income tax benefit (provision)	15.3	(16.5)	3.5	—	2.3
Net (loss) income	(26.2)	29.7	(5.6)	—	(2.1)
Net income attributable to noncontrolling interest	—	(1.0)	—	—	(1.0)
Net (loss) income attributable to QEP [3]	$(26.2)	$28.7	$(5.6)	$—	$(3.1)

(1) The impact of QEP's settled derivative contracts for the three months ended September 30, 2012 are reflected below operating (loss) income.

(2) Operating (loss) income for the three months ended September 30, 2012, excludes the impact of realized commodity derivative contract settlements. During the three months ended September 30, 2012, gains and losses from realized commodity derivative contract settlements were included below operating (loss) income.

(3) Net (loss) income attributable to QEP for the three months ended September 30, 2012 includes the impact of unrealized gains and losses from changes in the fair value of the commodity derivative contracts.

The following table is a summary of operating results for the three months ended September 30, 2011, by line of business:

	QEP Energy	QEP Field Services	QEP Marketing & Other	Eliminations	QEP Consolidated
	(in millions)				
Revenues [1]					
From unaffiliated customers	$635.6	$98.6	$145.7	$—	$879.9
From affiliated customers	—	21.0	148.5	(169.5)	—
Total Revenues	635.6	119.6	294.2	(169.5)	879.9
Operating expenses					
Purchased gas, oil and NGL expenses	208.1	—	292.0	(147.4)	352.7
Lease operating expense	38.0	—	—	(1.0)	37.0
Natural gas, oil and NGL transportation and other handling costs	45.0	2.5	—	(20.0)	27.5
Gathering, processing and other	—	26.6	0.4	—	27.0
General and administrative	23.0	6.6	0.2	(1.1)	28.7
Production and property taxes	26.3	1.4	—	—	27.7
Depreciation, depletion and amortization	174.4	14.0	0.6	—	189.0
Other operating expenses	8.1	—	—	—	8.1
Total operating expenses	522.9	51.1	293.2	(169.5)	697.7
Net gain (loss) from asset sales	1.2	(0.1)	0.1	—	1.2
Operating income [2]	113.9	68.4	1.1	—	183.4
Interest and other (loss) income	(0.7)	—	25.0	(25.0)	(0.7)
Income from unconsolidated affiliates	—	2.3	—	—	2.3
Loss on early extinguishment of debt	—	—	(0.7)	—	(0.7)
Interest expense	(20.5)	(3.8)	(23.5)	25.0	(22.8)
Income before income taxes	92.7	66.9	1.9	—	161.5
Income taxes	(34.4)	(24.0)	(0.7)	—	(59.1)
Net income	58.3	42.9	1.2	—	102.4
Net income attributable to noncontrolling interest	—	(0.9)	—	—	(0.9)
Net income attributable to QEP [3]	$58.3	$42.0	$1.2	$—	$101.5

(1) Revenues for the three months ended September 30, 2011, have been recast to reflect QEP's revised reporting of its transportation and handling costs. See Note 2 - Basis of Presentation of Interim Consolidated Financial Statements for additional information. In addition, revenues for the three months ended September 30, 2011, reflect the impact of QEP's settled derivative contracts. See Note 7 - Derivative Contracts for detailed information on derivative contract settlements in the three months ended September 30, 2011.

(2) Under hedge accounting, gains and losses from realized commodity derivative contract settlements were included in revenues and operating income during the three months ended September 30, 2011.

(3) Under hedge accounting, unrealized gains and losses from changes in the fair value were deferred in accumulated other comprehensive income during the three months ended September 30, 2011.

The following table is a summary of operating results for the nine months ended September 30, 2012, by line of business:

	QEP Energy	QEP Field Services	QEP Marketing & Other	Eliminations	QEP Consolidated
	(in millions)				
Revenues (1)					
From unaffiliated customers	$1,106.3	$254.9	$283.7	$—	$1,644.9
From affiliated customers	—	88.1	396.3	(484.4)	—
Total Revenues	1,106.3	343.0	680.0	(484.4)	1,644.9
Operating expenses					
Purchased gas, oil and NGL expense	159.0	9.0	681.7	(393.8)	455.9
Lease operating expense	125.3	—	—	(2.5)	122.8
Natural gas, oil and NGL transportation and other handling costs	167.4	27.7	—	(83.6)	111.5
Gathering, processing and other	—	65.6	0.8	—	66.4
General and administrative	94.3	24.1	0.6	(4.5)	114.5
Production and property taxes	63.6	4.6	0.2	—	68.4
Depreciation, depletion and amortization	597.7	47.2	2.5	—	647.4
Other operating expenses	78.1	—	—	—	78.1
Total operating expenses	1,285.4	178.2	685.8	(484.4)	1,665.0
Net gain from asset sales	1.5	—	—	—	1.5
Operating (loss) income (2)	(177.6)	164.8	(5.8)	—	(18.6)
Realized and unrealized gains (losses) on derivative contracts	330.4	8.3	(4.0)	—	334.7
Interest and other income	2.2	0.1	81.1	(81.0)	2.4
Income from unconsolidated affiliates	0.1	5.5	—	—	5.6
Loss on early extinguishment of debt	—	—	(0.6)	—	(0.6)
Interest expense	(71.1)	(9.4)	(83.4)	81.0	(82.9)
Income (loss) before income taxes	84.0	169.3	(12.7)	—	240.6
Income tax (provision) benefit	(32.4)	(59.2)	5.1	—	(86.5)
Net income (loss)	51.6	110.1	(7.6)	—	154.1
Net income attributable to noncontrolling interest	—	(2.7)	—	—	(2.7)
Net income (loss) attributable to QEP (3)	$51.6	$107.4	$(7.6)	$—	$151.4

(1) The impact of QEP's settled derivative contracts, for the nine months ended September 30, 2012, are reflected below operating (loss) income.

(2) Operating (loss) income for the nine months ended September 30, 2012, excludes the impact of realized commodity derivative contract settlements. During the nine months ended September 30, 2012, gains and losses from realized commodity derivative contract settlements were included below operating (loss) income.

(3) Net (loss) income attributable to QEP for the nine months ended September 30, 2012, includes the impact of unrealized gains and losses from changes in the fair value of the commodity derivative contracts.

The following table is a summary of operating results for the nine months ended September 30, 2011, by line of business:

	QEP Energy	QEP Field Services	QEP Marketing & Other	Eliminations	QEP Consolidated
	(in millions)				
Revenues [1]					
From unaffiliated customers	$1,587.3	$273.9	$444.7	$—	$2,305.9
From affiliated customers	—	64.5	426.8	(491.3)	—
Total Revenues	1,587.3	338.4	871.5	(491.3)	2,305.9
Operating expenses					
Purchased gas, oil and NGL expense	362.8	—	862.4	(421.9)	803.3
Lease operating expense	106.4	—	—	(2.3)	104.1
Natural gas, oil and NGL transportation and other handling costs	130.8	4.6	—	(62.2)	73.2
Gathering, processing and other	—	78.3	1.1	—	79.4
General and administrative	69.8	22.4	1.8	(4.9)	89.1
Production and property taxes	73.9	4.4	0.2	—	78.5
Depreciation, depletion and amortization	524.0	40.7	1.7	—	566.4
Other operating expenses	23.9	—	—	—	23.9
Total operating expenses	1,291.6	150.4	867.2	(491.3)	1,817.9
Net gain (loss) from asset sales	1.4	—	—	—	1.4
Operating income [2]	297.1	188.0	4.3	—	489.4
Interest and other income	(0.5)	—	74.2	(74.2)	(0.5)
Income from unconsolidated affiliates	0.1	4.4	—	—	4.5
Loss on extinguishment of debt	—	—	(0.7)	—	(0.7)
Interest expense	(60.8)	(10.4)	(70.0)	74.2	(67.0)
Income before income taxes	235.9	182.0	7.8	—	425.7
Income taxes	(87.7)	(65.6)	(2.7)	—	(156.0)
Net income	148.2	116.4	5.1	—	269.7
Net income attributable to noncontrolling interest	—	(2.2)	—	—	(2.2)
Net income attributable to QEP [3]	$148.2	$114.2	$5.1	$—	$267.5

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(1) Revenues for the nine months ended September 30, 2011, have been recast to reflect QEP's revised reporting of its transportation and handling costs. See Note 2 - Basis of Presentation of Interim Consolidated Financial Statements for additional information. In addition, revenues for the nine months ended September 30, 2011, reflect the impact of QEP's settled derivative contracts. See Note 7 - Derivative Contracts for detailed information on derivative contract settlements in the nine months ended September 30, 2011.

(2) Under hedge accounting, realized gains and losses from realized commodity derivative contract settlements were included in revenues and operating income during the three and nine months ended September 30, 2011.

(3) Under hedge accounting, unrealized gains and losses from changes in the fair value were deferred in accumulated other comprehensive income during the three and nine months ended September 30, 2011.

The following table is a summary of balance sheet information by line of business:

	QEP Energy	QEP Field Services	QEP Marketing & Other	Eliminations	QEP Consolidated
	(in millions)				

Total assets as of September 30, 2012	$7,416.1	$1,362.7	$217.3	$—	$8,996.1
Total assets as of December 31, 2011	5,815.7	1,312.7	314.3	—	7,442.7

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is intended to provide a reader of the financial statements with a narrative from the perspective of management on the financial condition, results of operations, liquidity and certain other factors that may affect the Company's operating results. MD&A should be read in conjunction with the Condensed Consolidated Financial Statements and related notes included in Item 1 of this Quarterly Report on Form 10-Q.

The following information updates the discussion of QEP's financial condition provided in its 2011 Annual Report on Form 10-K filing and analyzes the changes in the results of operations between the three and nine month periods ended September 30, 2012 and 2011. For definitions of commonly used gas and oil terms found in this Quarterly Report on Form 10-Q, please refer to the "Glossary of Commonly Used Terms" provided in QEP's 2011 Annual Report on Form 10-K.

OVERVIEW

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

- QEP Energy Company (QEP Energy) acquires, explores for, develops and produces natural gas, crude oil, and natural gas liquids (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;
- QEP Marketing Company (QEP Marketing) markets affiliate and third-party natural gas and oil, and owns and operates an underground gas storage reservoir.

Strategies

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

- Operate in a safe and environmentally responsible manner;
- Allocate capital to those projects that generate optimal returns;
- Maintain a sustainable, diverse inventory of low-cost, high-margin resource plays;
- Be in the highest-potential areas of the resource plays in which we operate;
- Build contiguous acreage positions that drive operating efficiencies;
- Be the operator of our assets, whenever possible;
- Be the low-cost driller and producer in each area where we operate;

- Own and operate midstream infrastructure in our core producing areas to capture value downstream of the wellhead;
- Build gas processing plants to extract liquids from our natural gas streams;
- Gather, compress and treat our production to drive down costs;
- Actively market our QEP Energy production to maximize value;
- Utilize derivative contracts to mitigate the impact of natural gas, crude oil or NGL price volatility, while locking in acceptable cash flows required to support future capital expenditures;

- Attract and retain the best people; and
- Maintain a capital structure that allows us the necessary financial flexibility with which to invest in organic growth and potential acquisition opportunities, as they may arise.

Outlook

The Company has substantial acreage positions and operations in some of the most prolific hydrocarbon resource plays in the continental United States, including the Bakken/Three Forks, Pinedale, Uinta Basin, Woodford “Cana” and Haynesville Shale. These resource plays are characterized by unconventional oil or natural gas accumulations in continuous tight sands or shales that underlie broad geographic areas. The lateral continuity of such resource plays means that aside from wells abandoned due to mechanical issues, the Company does not expect to drill unsuccessful wells. Resource plays allow the Company the opportunity to gain considerable operational efficiencies through high-density, repeatable drilling and completion operations. The Company has a large inventory of lower-risk, predictable development drilling locations across its acreage holdings in the onshore United States that provide a solid base for consistent growth in organic production and reserves. QEP believes that it has one of the lowest cash operating structures among its exploration and production company peers. However, in certain of its resource plays, QEP, like its peers, has experienced rising drilling and completion 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. As part of the Company's liquids growth strategy, QEP Energy acquired oil and gas properties in the Williston Basin for an aggregate purchase price of approximately $1.4 billion subject to post-closing adjustments (the “Acquisition”) during the third quarter of 2012. The results of operations for the three and nine months ended September 30, 2012, do not include the results of operations from the assets purchased in the Acquisition.

During the third quarter of 2012, QEP Energy increased its crude oil and NGL production by 56% compared with the third quarter of 2011. During the nine months ended September 30, 2012, QEP Energy increased its crude oil and NGL production by 86% compared with the nine months ended September 30, 2011. In the third quarter of 2012, crude oil and NGL revenue accounted for approximately 48% of QEP Energy’s field-level production revenues, compared with 32% in the third quarter of 2011. During the first three quarters of 2012, crude oil and NGL revenue accounted for approximately 50% of QEP Energy’s field-level production revenues, compared with 29% during the first three quarters of 2011. QEP Energy has allocated approximately 93% of its 2012 total forecasted capital expenditure budget to crude oil and liquids-rich natural gas plays.

While QEP believes that it can grow production and reserves from its extensive inventory of identified drilling locations, the Company continues to evaluate additional acquisition opportunities that might have the potential to create significant long-term value. QEP believes that its experience, expertise, and substantial presence in its core operating areas, combined with its low-cost operating model and financial strength, enhance its ability to pursue additional acquisition opportunities. In addition, from time to time the Company may seek to divest select non-core portfolio assets as it seeks to redirect capital towards higher-return projects.

QEP owns and operates gathering and transmission pipelines and natural gas processing and treatment facilities in many of its core producing areas. These assets enable the Company to promptly connect its wells, better control its costs, and generate a significant, consistent revenue stream by providing gathering and processing services to third parties.

Financial and Operating Results

During the three and nine months ended September 30, 2012, QEP Energy experienced substantial production growth, while QEP Field Services increased processing and gathering volumes. During the three and nine months ended September 30, 2012, QEP Energy reported total equivalent production of 81.5 Bcfe and 235.3 Bcfe, increases of 15% and 17% from the three and nine months ended September 30, 2011. QEP Field Services' gathering throughput volumes during the three and nine months ended September 30, 2012, were 2% and 5% higher, respectively, than the 2011 comparable periods. During the three and nine months ended September 30, 2012, QEP Field Services reported 3% and 24% increases in NGL sales volumes, respectively. QEP Field Services fee-based processing volumes were 2% and 4% higher in the three and nine months of 2012, respectively, when compared to the prior year periods.

The increases in production at QEP Energy and system throughput at QEP Field Services were offset by decreased commodity prices at both QEP Energy and QEP Field Services. For the three and nine months ended September 30, 2012, QEP Energy’s average total net realized equivalent price (including commodity derivative impact) was $5.14 per Mcfe and $5.24 per Mcfe, respectively, compared with $5.58 per Mcfe and $5.60 per Mcfe during the three and nine months ended September 30, 2011, respectively. In addition, at QEP Field Services, the increases in NGL sales volumes during the third quarter 2012 and the first three quarters of 2012 were offset by decreases in average net realized NGL sales prices. Specifically, during the third quarter 2012, a 32% decrease in the average net realized NGL sales price occurred, resulting in a 46% decrease to the keep-whole processing margin. During the first three quarters of 2012, QEP Field Services incurred a 20% decrease in average net realized NGL sales prices, resulting in a 20% decrease to the keep-whole processing margin when compared to the same period last year.

During the third quarter of 2012, QEP Energy acquired oil and gas properties in the Williston Basin for approximately $1.4 billion. The properties are located in Williams and McKenzie counties of North Dakota, approximately 12 miles west of QEP's existing core acreage in the Williston Basin.

During the third quarter of 2012, QEP completed a public offering for $650.0 million in aggregate principal amount of 5.25% senior notes due in May 2023 (2023 Senior Notes). The 2023 Senior Notes were issued at face value. The estimated net proceeds of $640.8 million were used to fund a portion of the Acquisition.

During the second quarter of 2012, QEP entered into a $300.0 million senior unsecured term loan agreement (Term Loan) with a group of financial institutions. The Term Loan provides for borrowings at short-term interest rates and contains covenants, restrictions and interest rates that are substantially the same as the Company's existing revolving credit agreement. The Term Loan matures in April 2017, and the maturity date may be extended one year with the agreement of the lenders. In conjunction with the Term Loan, QEP entered into interest rate swap contracts with an aggregate notional amount of $300.0 million that effectively lock in a fixed rate that QEP will pay over the duration of the Term Loan.

In the first quarter of 2012, QEP completed a public offering for $500.0 million in aggregate principal amount of 5.375% senior notes due in October 2022 (2022 Senior Notes). The 2022 Senior Notes were issued at face value. The net proceeds of $493.1 million were used to repay indebtedness under QEP's revolving credit facility.

Factors Affecting Results of Operations

Oil, Natural Gas, and NGL Prices

Historically, field-level 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, domestic natural gas supply has grown faster than natural gas demand, driven by advances in drilling and completion technologies, including horizontal drilling and multi-stage hydraulic fracturing. These changes have allowed producers to extract increased quantities of natural gas from shale, tight sand formations, and other unconventional reservoirs. Increased natural gas supplies have resulted in downward pressure on natural gas prices, while concern about the global economy and other factors has created volatility in the price of crude oil. Changes in the market prices for natural gas, crude oil, and NGL directly impact many aspects of QEP's business, including its financial condition, revenues, results of operations, planned drilling activity and related capital expenditures, liquidity, rate of growth, and costs of goods and services required to drill and complete wells, and may impact the carrying value of its oil and natural gas properties.

QEP uses commodity derivatives to reduce the volatility of the prices QEP receives for a portion of its production and to protect cash flow and returns on invested capital from a drop in commodity prices. Generally, QEP intends to enter into commodity derivative contracts for approximately 50% of its forecasted annual production by the end of the first quarter of each fiscal year. As of September 30, 2012, QEP Energy had approximately 70% of its remaining forecasted 2012 natural gas, oil and NGL equivalent production covered with fixed-price swaps or costless collars assuming 2012 annual production of 316.9 Bcfe, including 77% of its remaining forecasted 2012 natural gas production covered with fixed-price swaps assuming 2012 annual natural gas production of 247.1 Bcf. During the first three quarters of 2012, QEP entered into commodity derivative contracts for a greater portion of its 2012 natural gas production in light of concerns of oversupply in the natural gas market. See Item 3 “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, QEP Energy has allocated approximately 93% 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

The Company elected to discontinue hedge accounting beginning January 1, 2012, and unrealized gains and losses from mark-to-market valuations of all derivative positions are reflected as unrealized derivative gains or losses in the Company's income statement. See Note 7 - Derivative Contracts to the Condensed Consolidated Financial Statements, in Item 1, Part I of this Quarterly Report on Form 10-Q 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 the first three quarters of 2012 and in prior periods and may continue to incur these types of gains and losses in the future.

Global Geopolitical and Macroeconomic Factors

QEP continues to monitor the outlook of the global economy, including the European debt crisis and its potential impact on global economic growth and the banking and financial sectors, political unrest in the Middle East, a slowing of growth in Asia, particularly China, the United States federal budget deficit, changes in regulatory oversight policy and commodity price volatility. A dramatic decline in regional or global economic conditions, a major recession or depression, regional political instability, economic sanctions, war, or other factors beyond the control of QEP could have a significant impact on natural gas, NGL and crude oil supply, demand and prices.

Supply, Demand and Other Market Risk Factors

After peaking in late 2011, U.S. natural gas directed drilling rig count decreased in 2012, as natural gas producers reduced drilling for natural gas in response to low natural gas prices. The reduction in natural gas production lagged the downturn in the natural gas rig count because natural gas producers had a significant inventory of drilled wells waiting on completion. As a result of the lag, U.S. natural gas production did not decline in most producing areas until the third quarter of 2012. The U.S. natural gas market entered the storage injection season with record high inventory levels. However, the combination of strong natural gas demand from electric power generation, combined with recent declines in U.S. natural gas production, has led to a decrease in natural gas storage inventories below record highs to levels near the five-year high. This has resulted in a general firming of natural gas prices during the third quarter of 2012. Despite increased stability in natural gas prices during the third quarter of 2012, QEP expects U.S. natural gas prices to remain volatile and well below the five year average price over the near term. Continued low natural gas prices have caused U.S. E&P companies, including QEP, to shift capital investments away from predominantly dry gas areas towards fields that are known to have liquids-rich natural gas and crude oil deposits. This shift in focus has caused domestic NGL production to increase dramatically. The increased NGL supplies, the warmer than average winter of 2011-2012, and price dislocations from infrastructure bottlenecks in certain regions, have all contributed to a weakening in domestic NGL prices, particularly ethane. QEP expects NGL prices to remain volatile for the foreseeable future. QEP anticipates global crude oil prices to remain near current levels, assuming the global economy and socio-political backdrops remain relatively stable. Disruption to the global oil supply system, political and/or economic instability, and/or other factors could trigger additional volatility in crude oil prices. In addition, transportation, refining, or other infrastructure constraints could introduce significant price differentials between regional markets where QEP sells its crude oil production and national (NYMEX or Cushing) and global (Brent or U.S. Gulf Coast) markets. Because of the global and regional price volatility and the uncertainty around the commodity price environment, QEP continues to manage its capital spending program and financial flexibility accordingly.

Potential for Future Asset Impairments

During the first three quarters of 2012, U.S. natural gas prices were lower than in the first three quarters of 2011. The carrying value of some of the Company's properties is sensitive to declines in natural gas, crude oil and NGL prices. These assets are at risk of impairment if future prices for natural gas, crude oil or NGL prices 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, crude oil and NGL prices alone could result in an impairment of properties. For additional information see Item 1A - Risk Factors of Part I and see Item 8, Note 1 - Significant Accounting Policies of Part II of QEP's 2011 Annual Report on Form 10-K.

During the three and nine months ended September 30, 2012, QEP recorded impairment charges of $7.3 million and $68.7 million, on some of its oil and gas properties. The impairment charges related to the reduced value of certain fields resulting from lower natural gas, crude oil and NGL prices and impairments of unproven leasehold acquisition costs. Of the $68.7 million impairment charge in the nine months ended September 30, 2012, $49.3 million related to the non-cash, price-related impairment charge on proved properties incurred in the second quarter of 2012. Of the $68.7 million impairment charge during the nine months ended September 30, 2012, $60.0 million related to oil and gas properties in the Southern Region and $8.7 million related to oil and gas properties in the Northern Region.

Impact of Dodd-Frank Act

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), was passed by Congress and signed into law in July 2010. The Dodd-Frank Act is designed to provide a comprehensive framework for the regulation of the over-the-counter derivatives market with the intent to provide greater transparency and reduction of risk between counterparties. The Dodd-Frank Act subjects swap dealers and major swap participants to capital and margin requirements and requires many derivative transactions to be cleared on exchanges. The Dodd-Frank Act provides for a potential exemption from these clearing and cash collateral requirements for commercial end-users. QEP is currently evaluating the final rules of the Commodity Futures Trading Commission (CFTC) and assessing the impact on the Company’s risk management program. QEP believes it will meet the requirements for the commercial end-user clearing exception and be able to continue to execute derivative transactions and not be required to meet the mandated clearing requirements. The CFTC's final rules are expected to have an impact on many of QEP's derivatives counterparties, which may result in additional costs that might be passed on to the Company, thereby potentially decreasing the relative effectiveness of our derivatives and potential profitability.

Critical Accounting Estimates

QEP’s significant accounting policies are described in Item 7 of Part II of its 2011 Annual Report on Form 10-K. The Company’s Condensed Consolidated Financial Statements are prepared in accordance with United States Generally Accepted Accounting Principles (GAAP). The preparation of the Company’s Condensed Consolidated Financial Statements requires management to make assumptions and estimates that affect the reported results of operations and financial position. QEP’s accounting policies on gas and oil reserves, successful efforts accounting for gas and oil operations, impairment of gas and oil properties, asset retirement obligations, accounting for derivative contracts, revenue recognition, environmental obligations and other contingencies, benefit plan obligations, share-based compensation, and income taxes, among others, may involve a high degree of complexity and judgment on the part of management.

RESULTS OF OPERATIONS

Net Income (Loss)

QEP Resources’ net loss was $3.1 million, or $0.02 per diluted share, in the third quarter of 2012, compared to net income of $101.5 million, or $0.57 per diluted share, in the third quarter of 2011. The decline in net income during the third quarter of 2012 was attributable to a 145% decrease in QEP Energy’s net income and a 32% decrease in QEP Field Services net income. QEP Energy’s net income decreased in the third quarter of 2012 due to a $50.9 million unrealized loss on derivative contracts, deferred in AOCI in the first three quarters of 2011, and 8% lower net realized equivalent commodity prices, partially offset by increased production volumes. The decrease in QEP Field Services’ third quarter 2012 net income was driven by a 9% decline in gathering margins and a 19% decline in processing margins. Net income attributable to QEP for the first three quarters of 2012 was $151.4 million, or $0.85 per diluted share, compared to $267.5 million, or $1.50 per diluted share in the first three quarters of 2011. The decrease in the first three quarters of 2012 was due to a 65% decrease in QEP Energy’s net income and a 6% decrease in QEP Field Services net income. QEP Energy’s net income decreased during the first three quarters of 2012 due to a second quarter 2012 commodity price-related impairment charge on proved properties of $49.3 million and 6% lower net realized equivalent commodity prices partially offset by a $37.9 million unrealized gain on commodity derivative contracts and increased production volumes. QEP Field Services’ decrease in net income during the first three quarters of 2012 was driven by a 20% decrease in the keep-whole processing margin and 7% lower gathering margins.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Change	2012	2011	Change
	(in millions)					
QEP Energy	$(26.2)	$58.3	$(84.5)	$51.6	$148.2	$(96.6)
QEP Field Services	28.7	42.0	(13.3)	107.4	114.2	(6.8)
QEP Marketing and other	(5.6)	1.2	(6.8)	(7.6)	5.1	(12.7)
Net (loss) income attributable to QEP	$(3.1)	$101.5	$(104.6)	$151.4	$267.5	$(116.1)
Earnings per diluted share	$(0.02)	$0.57	$(0.59)	$0.85	$1.50	$(0.65)
Average diluted shares	177.9	178.5	(0.6)	178.6	178.5	0.1

Adjusted EBITDA

Management believes Adjusted EBITDA (a non-GAAP measure) is an important measure of the Company's cash flow, liquidity, and ability to incur and service debt, fund capital expenditures and make distributions to shareholders. The use of this measure allows investors to understand how management evaluates financial performance to make operating decisions and allocate resources. It is also an important measure for comparing the Company's financial performance to other gas and oil producing companies. In addition, Adjusted EBITDA is a measure used in the Company's debt covenants under its Credit Agreement and Term Loan.

Consistent with such debt covenants, management defines Adjusted EBITDA as net income before the following items: depreciation, depletion and amortization (DD&A), abandonment and impairment, interest and other income, interest expense, income taxes, unrealized gains and losses on derivative contracts, losses on early extinguishment of debt, 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 better align with industry practice and GAAP. This revised disclosure does not change current or prior period disclosure of net income or Adjusted EBITDA. For additional information, see Note 2 - Basis of Presentation of Interim Consolidated Financial Statements to the Condensed Consolidated Financial Statements, in Item 1, Part I of the Quarterly Report on Form 10-Q, for additional details.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Change	2012	2011	Change
	(in millions)					
QEP Energy	$262.8	$267.3	$(4.5)	$789.3	$757.0	$32.3
QEP Field Services	68.0	84.8	(16.8)	223.8	233.1	(9.3)
QEP Marketing and other	(2.1)	1.6	(3.7)	(0.2)	6.0	(6.2)
Adjusted EBITDA	$328.7	$353.7	$(25.0)	$1,012.9	$996.1	$16.8

Adjusted EBITDA decreased to $328.7 million during the third quarter of 2012, compared to $353.7 million in the third quarter of 2011. During the three months ended September 30, 2012, QEP Energy's Adjusted EBITDA decreased 2% due to a 16% decline in net realized natural gas prices and 23% lower net realized NGL prices, which were offset by a 15% increase in total production in QEP Energy. During the three months ended September 30, 2012, QEP Field Services' Adjusted EBITDA decreased 20% due to lower gathering and processing margins. During the first three quarters of 2012, Adjusted EBITDA increased to $1,012.9 million from $996.1 million in the first three quarters of 2011, despite 15% lower net realized natural gas prices, 1% lower net realized crude oil prices and 15% lower net realized NGL prices. The impact of lower net realized prices during the first three quarters of 2012 was partially offset by an 17% increase in total production at QEP Energy, and increased processing margins at QEP Field Services.

The following table is a reconciliation of Adjusted EBITDA to net income, the most comparable GAAP financial measure:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Change	2012	2011	Change
	(in millions)					
Net (loss) income attributable to QEP Resources	$(3.1)	$101.5	$(104.6)	$151.4	$267.5	$(116.1)
Net income attributable to non-controlling interest	1.0	0.9	0.1	2.7	2.2	0.5
Net (loss) income	(2.1)	102.4	(104.5)	154.1	269.7	(115.6)
Unrealized loss (gain) on derivative contracts	57.1	(27.9)	85.0	(32.8)	(86.7)	53.9
Net gain from asset sales	—	(1.2)	1.2	(1.5)	(1.4)	(0.1)
Interest and other loss (income)	0.2	0.7	(0.5)	(2.4)	0.5	(2.9)
Income tax (benefit) provision	(2.3)	59.1	(61.4)	86.5	156.0	(69.5)
Interest expense	30.0	22.8	7.2	82.9	67.0	15.9
Loss on early extinguishment of debt	—	0.7	(0.7)	0.6	0.7	(0.1)
Depreciation, depletion and amortization	234.1	189.0	45.1	647.4	566.4	81.0
Abandonment and impairment	9.5	5.7	3.8	71.8	16.4	55.4
Exploration expenses	2.2	2.4	(0.2)	6.3	7.5	(1.2)
Adjusted EBITDA	$328.7	$353.7	$(25.0)	$1,012.9	$996.1	$16.8

The following table is a reconciliation of QEP Energy Adjusted EBITDA to net income:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Change	2012	2011	Change
	(in millions)					
Net (loss) income attributable to QEP Energy	$(26.2)	$58.3	$(84.5)	$51.6	$148.2	$(96.6)
Unrealized loss (gain) on derivative contracts	50.9	(27.9)	78.8	(37.9)	(86.7)	48.8
Net gain from asset sales	—	(1.2)	1.2	(1.5)	(1.4)	(0.1)
Interest and other loss (income)	0.2	0.7	(0.5)	(2.2)	0.5	(2.7)
Income tax (benefit) provision	(15.3)	34.4	(49.7)	32.4	87.7	(55.3)
Interest expense	24.1	20.5	3.6	71.1	60.8	10.3
Depreciation, depletion and amortization	217.4	174.4	43.0	597.7	524.0	73.7
Abandonment and impairment	9.5	5.7	3.8	71.8	16.4	55.4
Exploration expenses	2.2	2.4	(0.2)	6.3	7.5	(1.2)
Adjusted EBITDA	$262.8	$267.3	$(4.5)	$789.3	$757.0	$32.3

The following table is a reconciliation of QEP Field Services Adjusted EBITDA to net income:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Change	2012	2011	Change
	(in millions)					
Net income attributable to QEP Field Services	$28.7	$42.0	$(13.3)	$107.4	$114.2	$(6.8)
Net income attributable to non-controlling interest	1.0	0.9	0.1	2.7	2.2	0.5
Net income	29.7	42.9	(13.2)	110.1	116.4	(6.3)
Unrealized loss (gain) on derivative contracts	2.5	—	2.5	(2.0)	—	(2.0)
Net gain from asset sales	—	0.1	(0.1)	—	—	—
Interest and other income	—	—	—	(0.1)	—	(0.1)
Income taxes	16.5	24.0	(7.5)	59.2	65.6	(6.4)
Interest expense	3.5	3.8	(0.3)	9.4	10.4	(1.0)
Depreciation, depletion and amortization	15.8	14.0	1.8	47.2	40.7	6.5
Adjusted EBITDA	$68.0	$84.8	$(16.8)	$223.8	$233.1	$(9.3)

The following table is a reconciliation of QEP Marketing and other Adjusted EBITDA to net income:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Change	2012	2011	Change
	(in millions)					
Net (loss) income attributable to QEP Marketing and other	$(5.6)	$1.2	$(6.8)	$(7.6)	$5.1	$(12.7)
Unrealized loss on derivative contracts	3.7	—	3.7	7.1	—	7.1
Net gain from asset sales	—	(0.1)	0.1	—	—	—
Interest and other income	—	—	—	(0.1)	—	(0.1)
Income tax (benefit) provision	(3.5)	0.7	(4.2)	(5.1)	2.7	(7.8)
Interest expense (income)	2.4	(1.5)	3.9	2.4	(4.2)	6.6
Loss on early extinguishment of debt	—	0.7	(0.7)	0.6	0.7	(0.1)
Depreciation, depletion and amortization	0.9	0.6	0.3	2.5	1.7	0.8
Adjusted EBITDA	$(2.1)	$1.6	$(3.7)	$(0.2)	$6.0	$(6.2)

Production

QEP Energy reported production of 81.5 Bcfe in the third quarter of 2012, a 15% increase when compared to the 70.7 Bcfe reported in the third quarter of 2011. On an energy-equivalent basis, crude oil and NGL comprised approximately 21% of QEP Energy's production during the third quarter of 2012, up from 15% for the third quarter of 2011. QEP Energy reported production of 235.3 Bcfe in the first three quarters of 2012, a 17% increase over the 201.3 Bcfe reported during the first three quarters of 2011. On an energy-equivalent basis, crude oil and NGL comprised approximately 20% of QEP Energy's production for the first three quarters, up from 13% for the first three quarters of

2011.

A summary of QEP Energy production is shown in the following table:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Change	2012	2011	Change
QEP Energy Production Volumes						
Natural gas (Bcf)	64.5	59.8	4.7	188.0	175.9	12.1
Oil (Mbbl)	1,442.6	922.6	520.0	3,973.1	2,559.2	1,413.9
NGL (Mbbl)	1,386.7	894.4	492.3	3,906.2	1,675.0	2,231.2
Total production (Bcfe)	81.5	70.7	10.8	235.3	201.3	34.0
Average daily production (MMcfe)	885.8	767.7	118.1	858.8	737.2	121.6

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Change	2012	2011	Change
QEP Energy - Natural gas Production (Bcf)						
Northern Region						
Pinedale	21.7	17.8	3.9	56.9	50.2	6.7
Uinta Basin	4.5	3.6	0.9	11.8	11.8	—
Legacy	3.0	2.9	0.1	9.0	9.0	—
Southern Region						
Haynesville/Cotton Valley	27.7	26.7	1.0	86.5	80.6	5.9
Midcontinent	7.6	8.8	(1.2)	23.8	24.3	(0.5)
Total production	64.5	59.8	4.7	188.0	175.9	12.1

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Change	2012	2011	Change
QEP Energy - Oil Production (Mbbl)						
Northern Region						
Pinedale	187.4	149.2	38.2	493.5	419.0	74.5
Uinta Basin	210.4	198.6	11.8	630.7	657.3	(26.6)
Legacy	660.9	379.0	281.9	1,806.9	906.6	900.3
Southern Region						
Haynesville/Cotton Valley	12.1	9.9	2.2	34.5	36.2	(1.7)
Midcontinent	371.8	185.9	185.9	1,007.5	540.1	467.4
Total production	1,442.6	922.6	520.0	3,973.1	2,559.2	1,413.9

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Change	2012	2011	Change
QEP Energy - NGL Production (Mbbl)						
Northern Region						
Pinedale	861.3	489.0	372.3	2,327.2	489.0	1,838.2
Uinta Basin	116.7	23.6	93.1	224.6	83.1	141.5
Legacy	47.5	33.5	14.0	137.1	89.8	47.3
Southern Region						
Haynesville/Cotton Valley	2.0	2.2	(0.2)	6.4	6.2	0.2
Midcontinent	359.2	346.1	13.1	1,210.9	1,006.9	204.0
Total production	1,386.7	894.4	492.3	3,906.2	1,675.0	2,231.2

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Change	2012	2011	Change
QEP Energy - Total Production (Bcfe)						
Northern Region						
Pinedale	28.0	21.6	6.4	73.9	55.6	18.3
Uinta Basin (1)	6.4	4.8	1.6	16.9	16.2	0.7
Legacy	7.3	5.6	1.7	20.6	15.1	5.5
Southern Region						
Haynesville/Cotton Valley	27.9	26.8	1.1	86.8	80.9	5.9
Midcontinent	11.9	11.9	—	37.1	33.5	3.6
Total production	81.5	70.7	10.8	235.3	201.3	34.0

(1) During the nine months ended September 30, 2011, the Uinta Basin production included a 1.6 Bcfe positive adjustment due to an increase of QEP's ownership interest within a federal unit.

Northern Region – Pinedale Division. Net production from Pinedale in western Wyoming grew 30% to 28.0 Bcfe in the third quarter of 2012 compared to the third quarter of 2011. Net production from Pinedale grew 33% to 73.9 Bcfe in the first three quarters of 2012 compared to the first three quarters of 2011. Pinedale production growth was driven by increased drilling activity and the fee-based processing agreement at Blacks Fork II entered into in the third quarter of 2011 between QEP Energy and QEP Field Services. As a result of the processing agreement, QEP Energy NGL production at Pinedale for the three and nine months ended September 30, 2012, was 861.3 Mbbl and 2,327.2 Mbbl, contrasted with 489.0 Mbbl in the comparable 2011 periods. During the three and nine months ended September 30, 2012, the Pinedale Division represented 34% and 31% of QEP Energy's total production compared to 31% and 28% during the three and nine months ended September 30, 2011, respectively.

Northern Region – Uinta Basin Division. In the Uinta Basin, production increased 33% to 6.4 Bcfe in the third quarter of 2012 from the third quarter of 2011 due to increased drilling activity in the Lower Mesaverde Formation in the Red Wash Unit. NGL production increased 93.1 Mbbl in the third quarter of 2012 compared to the third quarter of 2011 primarily as a result of QEP Energy executing a cryogenic, fee-based processing agreement with QEP Field Services for a portion of the Red Wash Unit natural gas production. During the first three quarters of 2012, Uinta Basin production increased 4% and NGL production increased 170%. During the three and nine months ended September 30, 2012, the Uinta Basin Division production represented 8% and 7% of QEP Energy's total production compared to 7% and 8% during the three and nine months ended September 30, 2011, respectively.

Northern Region – Legacy Division. QEP Energy Legacy Division properties include all Northern Region Rockies properties except the Pinedale Anticline and the Uinta Basin. Legacy Division net production during the third quarter of 2012 increased

30% to 7.3 Bcfe, driven by a 74% increase in crude oil production and a 42% increase in NGL production. During the first three quarters of 2012, net production in the Legacy Division increased 36% to 20.6 Bcfe due to a 99% increase in crude oil production and a 53% increase in NGL production. The increased production in the three and nine months ended September 30, 2012, was due to increased oil-directed drilling activity in the North Dakota Bakken/Three Forks play. During both the three and nine months ended September 30, 2012, the Legacy Division production represented 9% of QEP Energy's total production, compared to 7% during both the three and nine months ended September 30, 2011, respectively. These production results do not include production related to properties acquired in the Acquisition.

Southern Region – Haynesville/Cotton Valley Division. Net production from the Haynesville Shale and Cotton Valley tight gas plays in northwest Louisiana increased 4% to 27.9 Bcfe in the third quarter of 2012, when compared to the third quarter of 2011. During the first three quarters of 2012, net production from the Haynesville Shale and Cotton Valley plays increased 7% to 86.8 Bcfe. The increases during the three and nine months ended September 30, 2012, were due to the completion of several high-rate wells in early 2012 that were drilled during the latter half of 2011. QEP Energy has discontinued its operated, development drilling in the Haynesville shale and Cotton Valley tight gas plays in response to depressed natural gas prices. QEP Energy expects production from the Division to continue its decline from the second quarter of 2012 as the final operated rig was released in July of 2012. In addition, the completion of five wells that have been drilled and cased in 2012 are currently planned to be deferred until early 2013. During the three and nine months ended September 30, 2012, Haynesville/Cotton Valley production comprised 34% and 37% of QEP Energy's total production, respectively, compared to 38% and 40% in the three and nine months ended September 30, 2011, respectively.

Southern Region – Midcontinent Division. Net production in the Midcontinent was flat in the third quarter of 2012 when compared to the third quarter of 2011. Crude oil production increased 100% or 185.9 Mbbl and NGL production increased 4% or 13.1 Mbbl but was offset by a 1.2 Bcf decrease in natural gas production. During the first three quarters of 2012, net production in the Midcontinent grew 11% to 37.1 Bcfe compared to the first three quarters of 2011, driven by a 87% increase in crude oil production and a 20% increase in NGL production. Midcontinent production growth was driven by continued development of the Granite Wash/Marmaton/Tonkawa plays in Texas and western Oklahoma and the Woodford "Cana" Shale liquids-rich gas play in the Anadarko Basin of western Oklahoma. During the three and nine months ended September 30, 2012, the Midcontinent Division represented 15% and 16% of QEP Energy's total production, down from 17% during the third quarter and first three quarters of 2011.

Pricing

During the year ended December 31, 2011, QEP revised its reporting of natural gas, oil and NGL transportation and handling costs. Transportation and handling costs have been recast on the Condensed Consolidated Statement of Operations from revenues to "Natural gas, oil and NGL transportation and other handling costs" for all periods presented. Prior to the recast, transportation and other handling costs were netted against revenue and were reflected in field-level prices. See Note 2 - Basis of Presentation of Interim Consolidated Financial Statements to the Condensed Consolidated Financial Statements, in Item 1, Part I of this Quarterly Report on Form 10-Q, for additional information.

In addition, QEP Energy's field-level and realized prices (after the impact of all settled commodity derivatives) for natural gas, oil and NGLs were lower during the three and nine months ended September 30, 2012, as compared to the 2011 periods. A regional comparison of average field level prices is shown in the following tables:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Change	2012	2011	Change
QEP Energy - Average field-level natural gas price (per Mcf)						
Northern Region	$2.53	$3.92	$(1.39)	$2.42	$4.00	$(1.58)
Southern Region	2.73	4.04	(1.31)	2.56	4.08	(1.52)
Average field-level natural gas price	2.64	3.99	(1.35)	2.50	4.05	(1.55)
QEP Energy - Average field-level oil price (per bbl)						
Northern Region	$80.00	$80.80	$(0.80)	$82.04	$84.35	$(2.31)
Southern Region	86.01	88.46	(2.45)	91.38	90.88	0.50
Average field-level oil price	81.60	82.42	(0.82)	84.49	85.82	(1.33)
QEP Energy - Average field-level NGL price (per bbl)						
Northern Region	$30.75	$35.81	$(5.06)	$36.79	$40.64	$(3.85)
Southern Region	19.56	45.13	(25.57)	29.05	43.61	(14.56)
Average field-level NGL price	27.83	39.44	(11.61)	34.38	42.43	(8.05)

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012 (1)	2011 (2)	Change	2012 (1)	2011 (2)	Change
Natural gas (per Mcf)						
Average field-level price	$2.64	$3.99	$(1.35)	$2.50	$4.05	$(1.55)
Commodity derivative impact	1.34	0.73	0.61	1.51	0.69	0.82
Net realized price	$3.98	$4.72	$(0.74)	$4.01	$4.74	$(0.73)
Oil (per bbl)						
Average field-level price	$81.60	$82.42	$(0.82)	$84.49	$85.82	$(1.33)
Commodity derivative impact	1.83	0.91	0.92	0.55	0.37	0.18
Net realized price	$83.43	$83.33	$0.10	$85.04	$86.19	$(1.15)
NGL (per bbl)						
Average field-level price	$27.83	$39.44	$(11.61)	$34.38	$42.43	$(8.05)
Commodity derivative impact	2.46	—	2.46	1.66	—	1.66
Net realized price	$30.29	$39.44	$(9.15)	$36.04	$42.43	$(6.39)

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(1) The impact from commodity derivatives is reported below operating (loss) income in "Realized and unrealized gains on derivative contracts" beginning January 1, 2012, in the Condensed Consolidated Statement of Operations.

(2) The impact of settled commodity derivatives that qualified for hedge accounting was reported in "Revenues" in the Condensed Consolidated Statement of Operations. The impact of the commodity derivatives that did not qualify for hedge accounting are reported below operating (loss) income in "Realized and unrealized gains on derivative contracts."

Gathering

During the three and nine months ended September 30, 2012, QEP Field Services gathering margins declined 9% and 7%, respectively, due mainly to a decrease in other gathering revenue and related margin from the elimination of a third-party interruptible processing agreement. Partially offsetting the decline in gathering margin was a 2% and a 5% increase in gathering system throughput volume and a 3% increase in average gas gathering revenue per MMBtu during the three and nine months

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ended September 30, 2012, respectively. Gathering system throughput volume was 1.4 million MMBtu per day for the three and nine months ended September 30, 2012, compared to 1.4 million MMBtu per day and 1.3 million MMBtu per day during the three and nine months ended September 30, 2011, respectively. The increased volumes were mainly related to the gathering system tied into the Blacks Fork hub in Southwest Wyoming, which were 6% and 7% higher in the three and nine months ended September 30, 2012, respectively, and the northwest Louisiana gathering system, which were 3% and 14% higher in the three and nine months September 30, 2012, respectively. The Blacks Fork hub accounted for 53% and 51% of the total gathering system throughput during the three and nine months ended September 30, 2012, compared to 51% and 50% in the three and nine months ended September 30, 2011, while the Louisiana hub accounted for 22% and 24% of the total throughput during the three and nine months ended September 30, 2012, compared to 22% during both the three and nine months ended September 30, 2011, respectively.

During the three and nine months ended September 30, 2011, QEP Field Services reported other gathering revenues and related gathering expense related to a short-term interruptible gas processing contract with a third-party processor. The short-term processing arrangement was in effect prior to the startup of QEP Field Service's Blacks Fork II processing plant. Of the $8.5 million and $30.6 million decrease in other gathering revenues, $9.2 million and $32.6 million of the decrease related to the elimination of this contract. In addition, gathering expenses related to the elimination of this contract were $3.0 million and $10.7 million lower during the three and nine months ended September 30, 2012.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Change	2012	2011	Change
Gathering Margin		(in millions)		(in millions)		
Gathering revenues	$43.9	$41.9	$2.0	$131.6	$120.0	$11.6
Other gathering revenues	8.0	16.5	(8.5)	28.6	59.2	(30.6)
Gathering expense	(9.0)	(11.0)	2.0	(26.9)	(35.3)	8.4
Gathering margin	$42.9	$47.4	$(4.5)	$133.3	$143.9	$(10.6)
Operating Statistics						
Natural gas gathering volumes (in millions of MMBtu)						
For unaffiliated customers	60.2	66.3	(6.1)	184.4	193.4	(9.0)
For affiliated customers	69.1	60.6	8.5	202.5	173.6	28.9
Total Gas Gathering Volumes	129.3	126.9	2.4	386.9	367.0	19.9
Average gas gathering revenue (per MMBtu)	$0.34	$0.33	$0.01	$0.34	$0.33	$0.01

Processing

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

QEP Field Services processing margin decreased 19% during the third quarter of 2012, but increased 1% during the first three quarters of 2012. The decrease in the processing margin during the third quarter of 2012 was due to a 46% decline in keep-whole processing margins, partially offset by an 18% increase in fee-based processing revenues.

During the first three quarters of 2012 fee-based processing revenues increased 38% , partially offset by a 20% decrease in the keep-whole processing margin.

During the third quarter and first three quarters of 2012, keep-whole processing margins decreased due to a decrease in the net realized NGL sales price per gallon, offset by increased NGL sales volumes. Including the impact of gains on derivative contract settlements, NGL prices decreased 32% and 20% in the three and nine months ended September 30, 2012, respectively, compared to the three and nine months ended September 30, 2011, which caused a corresponding decrease in the keep-whole processing margin per NGL gallon. During the three and nine months ended September 30, 2012, the keep-whole processing margin per NGL gallon was $0.45 and $0.53, respectively, compared to $0.86 and $0.83 during the three and nine months ended September 30, 2011, respectively. NGL sales volumes increased 3% and 24% in the three and nine months ended September 30, 2012, respectively, compared to the 2011 periods. The increased NGL sales volumes in the third quarter and first three quarters of 2012 were primarily the result of the Blacks Fork II plant which commenced operations in July 2011, partially offset by the execution, in the second quarter of 2012, of a fee-based processing agreement with QEP Energy in the Uinta Basin that effectively transferred NGL gallons from QEP Field Services to QEP Energy.

Fee-based processing revenues increased during the third quarter of 2012 due to a 17% increase in average fee-based processing revenue to $0.28 per MMBtu and a 2% increase in fee-based processing volumes to 65.0 million MMBtu. During the first three quarters of 2012, the increase in fee-based processing revenues was the result of a 29% increase in average fee-based processing revenue per MMBtu and a 4% increase in fee-based processing volumes. Approximately 80% and 76% of QEP Field Services' net operating revenue was derived from fee-based gathering and processing agreements in the three and nine months ended September 30, 2012, respectively, compared to 72% and 73% during the three and nine months ended September 30, 2011, respectively.

Keep-whole processing margin, as reflected in the table below, is defined as the market value for NGLs extracted from the natural gas stream less the market value of the Btu-equivalent volume of natural gas required to replace the extracted liquids and the related transportation and handling (including fractionation) costs. Transportation and handling costs were $4.4 million and $23.1 million higher during the three and nine months ended September 30, 2012, respectively, primarily as a result of additional transportation costs relating to NGL sale agreements that provide for transportation and fractionation of NGL's at Mont Belvieu, Texas, and the 2012 operation of the Blacks Fork II plant, which was put into service in July of 2011.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Change	2012	2011	Change
Processing Margin	(in millions)					
NGL sales [1]	$28.9	$44.1	$(15.2)	$112.7	$119.9	$(7.2)
Realized gains from commodity derivative contract settlements	1.9	—	1.9	6.3	—	6.3
Processing (fee-based) revenues	18.2	15.4	2.8	51.8	37.6	14.2
Other processing fees	5.4	1.7	3.7	8.4	1.7	6.7
Processing (expense)	(4.7)	(3.1)	(1.6)	(12.1)	(8.9)	(3.2)
Processing plant fuel and shrink (expense)	(8.1)	(12.5)	4.4	(26.6)	(34.1)	7.5
Natural gas, oil and NGL transportation and other handling costs	(6.9)	(2.5)	(4.4)	(27.7)	(4.6)	(23.1)
Processing margin	$34.7	$43.1	$(8.4)	$112.8	$111.6	$1.2
Keep-whole processing margin	$15.8	$29.1	$(13.3)	$64.7	$81.2	$(16.5)
Operating Statistics						
Natural gas processing volumes						
NGL sales (MMgal)	34.9	34.0	0.9	121.5	98.2	23.3
Average net realized NGL sales price (per gal)[2]	$0.88	$1.30	$(0.42)	$0.98	$1.22	$(0.24)
Fee-based processing volumes (in millions of MMBtu)						
For unaffiliated customers	26.0	31.9	(5.9)	83.7	96.4	(12.7)
For affiliated customers	39.0	31.9	7.1	105.5	84.7	20.8
Total fee-based processing volumes	65.0	63.8	1.2	189.2	181.1	8.1
Average fee-based processing revenue (per MMBtu)	$0.28	$0.24	$0.04	$0.27	$0.21	$0.06

(1) NGL sales for the three and nine months ended September 30, 2011, have been recast to reflect QEP's revised reporting of its transportation and handling costs. See Note 2 - Basis of Presentation of Interim Consolidated Financial Statements for additional information. In addition, revenues for the three and nine months ended September 30, 2011, reflect the impact of QEP's settled derivative contracts which during the three and nine months ended September 30, 2012, are reflected below operating (loss) income. See Note 7 - Derivative Contracts for detailed information on derivative contract settlements in the three and nine months ended September 30, 2011.

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

Revenue, Volume and Price Variance Analysis

On January 1, 2012, QEP discontinued hedge accounting. During the three and nine months ended September 30, 2012, commodity derivative realized gains and losses from derivative contract settlements were included below operating (loss) income in "Realized and unrealized gains on derivative contracts" on the Condensed Consolidated Statement of Operations. Conversely, during the three and nine months ended September 30, 2011, the commodity derivative realized gains and losses on settlements were included in each respective revenue category in conjunction with hedge accounting and the realization of the underlying contract. For additional information regarding the discontinuance of hedge accounting and impact on the Condensed Consolidated Statement of Operations, see Note 7 -

Derivative Contracts, in Part I, Item 1 of this Quarterly Report on Form 10-Q.

The following table is a summary of QEP's total revenues:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Change	2012	2011	Change
	(in millions)					
QEP Resources Revenues						
Natural gas sales	$170.3	$309.8	$(139.5)	$470.4	$921.1	$(450.7)
Oil sales	117.7	76.9	40.8	335.7	220.6	115.1
NGL sales	67.5	79.3	(11.8)	247.0	191.0	56.0
Gathering, processing and other	46.3	57.1	(10.8)	141.9	162.6	(20.7)
Purchased gas and oil sales	140.6	356.8	(216.2)	449.9	810.6	(360.7)
Total Revenues	$542.4	$879.9	$(337.5)	$1,644.9	$2,305.9	$(661.0)

QEP Energy's revenues for the three and nine months ended September 30, 2012, generated from the sale of natural gas, oil and NGLs, decreased primarily due to lower prices for natural gas, crude oil and NGL, partially offset by higher production volumes, as follows:

	Natural Gas	Oil	NGLs	Total
	(in millions)			
QEP Energy Production Revenues				
Three months ended September 30, 2011 Revenues	$309.8	$76.9	$35.2	$421.9
Changes associated with volumes (1)	19.3	42.7	15.5	77.5
Changes associated with prices (2)	(87.2)	(1.0)	(12.1)	(100.3)
Changes associated with discontinuance of hedge accounting (3)	(71.6)	(0.9)	—	(72.5)
Three months ended September 30, 2012 Revenues	$170.3	$117.7	$38.6	$326.6

	Natural Gas	Oil	NGLs	Total
	(in millions)			
QEP Energy Production Revenues				
Nine months ended September 30, 2011 Revenues	$921.1	$220.6	$71.1	$1,212.8
Changes associated with volumes (1)	49.4	121.1	95.2	265.7
Changes associated with prices (2)	(291.0)	(5.0)	(32.0)	(328.0)
Changes associated with discontinuance of hedge accounting (3)	(209.1)	(1.0)	—	(210.1)
Nine months ended September 30, 2012 Revenues	$470.4	$335.7	$134.3	$940.4

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(1) The revenue variance attributed to the change in volume is calculated by multiplying the change in volumes from the three and nine months ended September 30, 2012, to the three and nine months ended September 30, 2011, by the average field-level price for the three and nine months ended September 30, 2011.

(2) The revenue variance attributed to the change in price is calculated by multiplying the change in field-level prices or fee from the three and nine months ended September 30, 2012, to the three and nine months ended September 30, 2011, by volume for the three and nine months ended September 30, 2012. Pricing changes are driven by changes in the commodity field-level prices excluding impact from commodity derivatives.

(3) During the three and nine months ended September 30, 2011, realized gains and losses on commodity derivative contract settlements were included in natural gas revenues on the Condensed Consolidated Statement of Operations. Conversely, during the three and nine months ended September 30, 2012, the realized gains and losses

on commodity derivative contract settlements are recognized below operating (loss) income on the Condensed Consolidated Statement of Operations.

QEP Field Services gathering and processing revenues decreased during the third quarter and first three quarters of 2012 compared to the third quarter and first three quarters of 2011. During the three and nine months ended September 30, 2012, various factors decreased gathering revenues including the elimination of a short-term, third-party, interruptible processing agreement recorded as other gathering revenues and reflected as a change associated with other factors. Changes associated with other factors increased processing revenues by $3.7 million and $6.7 million during the three and nine months ended September 30, 2012, respectively, due to charges to customers recorded as other processing fees at QEP Field Services. The following table presents changes in QEP Field Services major revenue categories and the related volume and pricing impact:

	Three Months Ended September 30,			
	NGLs	Processing	Gathering	Total
	(in millions)			
QEP Field Services				
Three months ended September 30, 2011 Revenues	$44.1	$17.1	$58.4	$119.6
Changes associated with volumes [1]	2.3	(0.2)	0.9	3.0
Changes associated with prices/fees [2]	(17.5)	3.0	1.1	(13.4)
Changes associated with other factors [3]	—	3.7	(8.5)	(4.8)
Three months ended September 30, 2012 Revenues	$28.9	$23.6	$51.9	$104.4

	Nine Months Ended September 30,			
	NGLs	Processing	Gathering	Total
	(in millions)			
QEP Field Services				
Nine months ended September 30, 2011 Revenues	$119.9	$39.3	$179.2	$338.4
Changes associated with volumes [1]	28.8	1.2	6.6	36.6
Changes associated with prices/fees [2]	(36.0)	13.0	5.0	(18.0)
Changes associated with other factors [3]	—	6.7	(30.6)	(23.9)
Nine months ended September 30, 2012 Revenues	$112.7	$60.2	$160.2	$333.1

(1) The revenue variance attributed to the change in volume is calculated by multiplying the change in volumes from the three and nine months ended September 30, 2012, to the three and nine months ended September 30, 2011, by the average price or fee for the three and nine months ended September 30, 2011.

(2) The revenue variance attributed to the change in fees is calculated by multiplying the change in prices or fees from the three and nine months ended September 30, 2012, to the three and nine months ended September 30, 2011, by volume for the three and nine months ended September 30, 2012.

(3) The revenue variance attributed to the change associated with other factors represents the changes in other gathering revenues and changes in other processing fees. These other revenues are not included in average gathering revenue per MMBtu or average fee-based processing revenue per MMBtu in QEP Field Services operating statistics and thus have not been included in the price and volume variance analysis presented above.

Purchased gas, oil and NGL sales decreased by $216.2 million and $360.7 million, or 61% and 44%, during the three and nine months ended September 30, 2012, respectively, from 2011. The decreases in the three and nine months ended September 30, 2012, were due to decreased resale natural gas volumes and prices. Resale natural gas volumes were 60% and 29% lower during the three and nine months ended September 30, 2012, while resale natural gas prices were 41% and 44% lower during the three and nine months ended September 30, 2012, respectively.

Operating Expenses

The following table presents QEP Resources' total operating expenses and the changes from the three and nine months ended September 30, 2012, to the three and nine months ended September 30, 2011. The narrative following the table explains the significant variances between the comparable periods.

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Change	2012	2011	Change
	(in millions)					
Purchased gas and oil expense	$142.6	$352.7	$(210.1)	$455.9	$803.3	$(347.4)
Lease operating expense	42.2	37.0	5.2	122.8	104.1	18.7
Natural gas, oil and NGL transportation and other handling costs	36.3	27.5	8.8	111.5	73.2	38.3
Gathering, processing and other	22.1	27.0	(4.9)	66.4	79.4	(13.0)
General and administrative	41.7	28.7	13.0	114.5	89.1	25.4
Production and property taxes	24.3	27.7	(3.4)	68.4	78.5	(10.1)
Depreciation, depletion and amortization	234.1	189.0	45.1	647.4	566.4	81.0
Exploration expenses	2.2	2.4	(0.2)	6.3	7.5	(1.2)
Abandonment and impairment	9.5	5.7	3.8	71.8	16.4	55.4
Total operating expenses	$555.0	$697.7	$(142.7)	$1,665.0	$1,817.9	$(152.9)

Purchased gas, oil and NGL expense decreased 60% and 43% in the three and nine months ended September 30, 2012, respectively. The decreases during both the three and nine months ended September 30, 2012 were due to 41% and 44% lower natural gas purchased prices, and 57% and 24% lower natural gas purchased volumes.

Lease operating expense increased 14% and 18% during the three and nine months ended September 30, 2012, respectively, due to higher water disposal costs, and increased trucking, chemical, labor and pumper costs. Water disposal costs increased $1.6 million and $7.1 million during the three and nine months ended September 30, 2012, respectively, primarily in the Northern Region due to increased drilling activity and related water disposal constraints in the Williston Basin. During the three and nine months ended September 30, 2012, trucking, labor and pumper costs increased $4.3 million and $8.9 million, respectively, primarily in the Northern Region due to increased drilling activity and liquids production in the Williston Basin.

For the three and nine months ended September 30, 2012, natural gas, oil and NGL transportation and other handling costs increased $8.8 million and $38.3 million, respectively, when compared to the corresponding period in 2011. The increases during the three and nine months ended September 30, 2012, are primarily due to transportation costs relating to agreements that provide for transportation and fractionation of NGL's at Mont Belvieu, Texas and the 2012 operation of the Blacks Fork II plant which was put into service in the third quarter of 2011. See Note 2 - Basis of Presentation and of Interim Consolidated Financial Statements to the Condensed Consolidated Financial Statements, in Item 1, Part I of this Quarterly Report on Form 10-Q, for a discussion of the recasting of 2011 transportation and other handling costs.

Gathering, processing and other expense decreased by $4.9 million and $13.0 million for the three and nine months ended September 30, 2012, respectively, due to lower gathering expenses from the elimination of a short-term, third-party interruptible processing agreement in which QEP Field Services was required to purchase the shrink gas. The short-term processing arrangement was in effect during the first half of 2011 before the expansion of the Blacks Fork processing plant was put into service during the third quarter of 2011.

For the third quarter of 2012, general and administrative (G&A) expense increased $13.0 million to $41.7 million, compared to the same period in 2011. The increase in G&A during the third quarter of 2012 was primarily due to a $3.4 million increase from changes in the Company's stock prices impacting the mark-to-market of the deferred compensation wrap plan, $2.6 million in higher costs due to increased headcount and the annual compensation program, $2.5 million increase in professional and outside services, $2.3 million increase in charitable contributions,

$1.5 million in higher stock-based compensation expense and $0.2 million attributable to restructuring costs (see Note 8 – Restructuring Costs of this Form 10-Q for additional information on the restructuring costs) offset slightly by various other immaterial decreases. G&A expense increased $25.4 million, or 29%, during the first three quarters of 2012 when compared to the first three quarters of 2011. The increase in G&A in the first three quarters of 2012 was primarily due to $5.3 million in restructuring costs, $5.5 million increase in professional and outside services, $5.4 million in higher costs due to increased headcount and the annual compensation program, $3.0 million increase in stock-based compensation expense, $2.4 million from the mark-to-market of the deferred compensation wrap plan, $2.2 million increase in charitable contributions with the remaining increases related to various immaterial items.

Production and property taxes decreased 12% for the third quarter of 2012 and 13% during the first three quarters of 2012. The decrease in the three and nine months ended September 30, 2012 was due to a 19% and a 20% decrease, respectively, in field-level equivalent sales prices which are used as the basis for production taxes in most states where QEP operates.

For the three and nine months ended September 30, 2012, QEP's total DD&A expense grew $45.1 million, or 24%, and $81.0 million, or 14%, respectively, as compared to the same periods in 2011. The third quarter and first three quarters of 2012 increases in DD&A expense were the result of increased production and increased DD&A rates in all Divisions at QEP Energy. Also contributing to the increase in DD&A expense during the nine months ended September 30, 2012, was the completion of the Blacks Fork II plant during the third quarter of 2011 at QEP Field Services.

Exploration expenses decreased $0.2 million, or 8%, during the third quarter of 2012 and decreased $1.2 million, or 16%, in the first three quarters of 2012 compared with 2011 periods. The first three quarters of 2012 decrease primarily related to a decrease of $0.4 million in dry hole expense, a $0.4 million decrease in delay rentals and a $0.4 million decrease in exploration related labor costs.

Abandonment and impairment expenses increased $3.8 million in the third quarter of 2012 compared with the third quarter of 2011. The third quarter of 2012 increase related to write-offs of expiring leasehold costs, primarily of unproved properties in the Midcontinent Division. During the first three quarters of 2012, abandonment and impairment expenses increased $55.4 million from the first three quarters of 2011. The increase in the first three quarters of 2012 was primarily due to the $49.3 million impairment of proved properties combined with an increase in the write-offs of expiring leasehold costs included in unproved properties. The Company's proved properties have significant reserves and are sensitive to declines in natural gas, crude oil and NGL prices. These assets are at risk of impairment if future natural gas, crude oil or NGL prices experience significant declines.

CONSOLIDATED RESULTS BELOW OPERATING (LOSS) INCOME

Realized and unrealized gain on derivative contracts

Effective January 1, 2012, QEP discontinued hedge accounting, thus changes during the three and nine months ended September 30, 2012, and all changes in mark-to-market are recognized in the current period earnings. In 2011, QEP used hedge accounting and changes in the mark-to-market value of the commodity derivative contracts were reflected in AOCI and ultimately revenues when the commodity derivatives were settled. Gains and losses on derivative instruments during 2012 are comprised of both realized and unrealized gains and losses on QEP's commodity derivative contracts and interest rate swaps. During the third quarter of 2012, gains on commodity derivative instruments were $39.0 million, of which $93.8 million was realized, partially offset by a $54.8 million unrealized loss on commodity derivative instruments. During the first three quarters of 2012, gains on commodity derivative instruments were $341.9 million, of which $302.5 million was realized and $39.4 million was unrealized. Additionally, during the third quarter of 2012, QEP recognized a loss from its interest rate swaps of $2.9 million, of which $0.6 million was realized and $2.3 million was unrealized. During the first three quarters of 2012, losses from interest rate swaps were $7.2 million, of which $0.6 million was realized and $6.6 million was unrealized.

Interest and other income

Interest and other income are comprised primarily of interest earned on investments, gains and losses on warehouse inventory, and other miscellaneous income. During the three and nine months ended September 30, 2012, interest and other income increased $0.5 million and $2.9 million, respectively. The increases were primarily due to the discontinuance of hedge accounting in the three and nine months ended September 30, 2012, compared to a $2.7 million and $2.6 million of losses due to hedge ineffectiveness recognized in three and nine months ended September

30, 2011, respectively. These increases were partially offset by variances in warehouse inventory valuations of $1.6 million and $1.5 million for the three and nine months ended September 30, 2012, respectively, when compared to the prior year periods.

Loss from early extinguishment of debt

During the first three quarters of 2012, QEP recorded a loss from early extinguishment of debt of $0.6 million from the retirement of a portion of QEP's Senior Notes. During the three and nine months ended September 30, 2011, QEP recorded a loss from early extinguishment of debt of $0.7 million due to replacing the previous $1.0 billion revolving credit facility with a new $1.5 billion revolving credit facility in August 2011.

Interest expense

Interest expense increased $7.2 million, or 32%, during the third quarter of 2012 when compared to the third quarter of 2011.

The increase in third quarter 2012 interest expense was attributable to average debt levels that were approximately $945.4 million higher than average debt levels in the third quarter of 2011. During the first three quarters of 2012, interest expense increased $15.9 million, or 24%, when compared to the first three quarters of 2011. The increase in interest expense during the first three quarters of 2012 was due to average debt levels that were approximately $872.7 million higher than average debt levels in the first three quarters of 2011. The increase in average debt levels is mostly related to the issuance of QEP's 2022 Senior Notes, 2023 Senior Notes and Term Loan in the first three quarters of 2012.

Income taxes

QEP's effective combined federal and state income tax rate was 52.3% for the third quarter of 2012, higher than the 36.6% in the third quarter of 2011. The higher third quarter of 2012 combined effective rate resulted from the size of tax deduction adjustment items in relation to the small net loss generated in the third quarter. The effective combined federal and state income tax rate was 36.0% for the first three quarters of 2012, compared to 36.6% in the first three quarters of 2011. The first three quarters of 2012 had a combined rate that was slightly lower due to a lower tax rate in the first quarter of 2012, resulting from changes in estimates and subsequent reduction of accruals that are non-deductible for income tax purposes.

DISCUSSION BY LINE OF BUSINESS

QEP Energy

QEP Energy reported a net loss of $26.2 million in the third quarter of 2012, a decrease of $84.5 million from the $58.3 million net income reported in the third quarter of 2011. The decline in third quarter of 2012 net income was primarily due an unrealized loss from commodity derivative instruments of $50.9 million combined with 8% lower average total equivalent net realized prices, partially offset by increased production volumes. During the first three quarters of 2012, QEP Energy reported net income of $51.6 million, a 65% decrease from the $148.2 million in the first three quarters of 2011. The primary reasons for the decrease in the first three quarters of 2012 were a $49.3 million non-cash impairment on proved properties and 6% lower average total equivalent net realized prices, partially offset by an unrealized gain from commodity derivative contracts of $37.9 million and increased production.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Change	2012	2011	Change
	(in millions)					
Revenues						
Natural gas sales	$170.3	$309.8	$(139.5)	$470.4	$921.1	$(450.7)
Oil sales	117.7	76.9	40.8	335.7	220.6	115.1
NGL sales	38.6	35.2	3.4	134.3	71.1	63.2
Purchased gas, oil and NGL sales	45.3	211.2	(165.9)	159.1	367.2	(208.1)
Other	2.1	2.5	(0.4)	6.8	7.3	(0.5)
Total Revenues	374.0	635.6	(261.6)	1,106.3	1,587.3	(481.0)
Operating expenses						
Purchased gas, oil and NGL expense	45.9	208.1	(162.2)	159.0	362.8	(203.8)
Lease operating expense	43.1	38.0	5.1	125.3	106.4	18.9
Natural gas, oil and NGL transportation and other handling costs	59.8	45.0	14.8	167.4	130.8	36.6
General and administrative	32.2	23.0	9.2	94.3	69.8	24.5
Production and property taxes	22.5	26.3	(3.8)	63.6	73.9	(10.3)
Depreciation, depletion and amortization	217.4	174.4	43.0	597.7	524.0	73.7
Exploration expenses	2.2	2.4	(0.2)	6.3	7.5	(1.2)
Abandonment and impairment	9.5	5.7	3.8	71.8	16.4	55.4
Total Operating Expenses	432.6	522.9	(90.3)	1,285.4	1,291.6	(6.2)
Net gain from asset sales	—	1.2	(1.2)	1.5	1.4	0.1
Operating (Loss) Income	(58.6)	113.9	(172.5)	(177.6)	297.1	(474.7)
Realized gain (loss) on derivative instruments	92.3	(27.9)	120.2	292.5	(86.7)	379.2
Unrealized (loss) gain on derivative instruments	(50.9)	27.9	(78.8)	37.9	86.7	(48.8)
Interest and other (loss) income	(0.2)	(0.7)	0.5	2.2	(0.5)	2.7
Income from unconsolidated affiliates	—	—	—	0.1	0.1	—
Interest expense	(24.1)	(20.5)	(3.6)	(71.1)	(60.8)	(10.3)
(Loss) Income before Income Taxes	(41.5)	92.7	(134.2)	84.0	235.9	(151.9)
Income tax benefit (provision)	15.3	(34.4)	49.7	(32.4)	(87.7)	55.3
Net (Loss) Income Attributable to QEP	$(26.2)	$58.3	$(84.5)	$51.6	$148.2	$(96.6)

Operating expenses per unit

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 5% to $4.89 per Mcfe in the third quarter of 2012 compared to $4.64 per Mcfe in the third quarter of 2011. Total operating expenses per Mcfe decreased 1% to $4.75 per Mcfe in the first three quarters of 2012 compared to $4.80 per Mcfe in the first three quarters of 2011. The following table presents certain QEP Energy operating expenses on a units of production basis.

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Change	2012	2011	Change
	(per Mcfe)					
Depreciation, depletion and amortization	$2.67	$2.47	$0.20	$2.54	$2.60	$(0.06)
Lease operating expense	0.53	0.54	(0.01)	0.53	0.53	—
Natural gas, oil and NGL transportation and other handling costs	0.73	0.64	0.09	0.71	0.65	0.06
General and administrative expense	0.39	0.33	0.06	0.40	0.35	0.05
Allocated interest expense	0.30	0.29	0.01	0.30	0.30	—
Production taxes	0.27	0.37	(0.10)	0.27	0.37	(0.10)
Total Operating Expenses	$4.89	$4.64	$0.25	$4.75	$4.80	$(0.05)

DD&A expense increased $0.20 per Mcfe in the third quarter of 2012 when compared to the third quarter of 2011. The increase in DD&A expense per Mcfe was the result of increased production from higher-rate DD&A pools and increases in those higher DD&A rate pools from increased drilling costs in the Midcontinent and Legacy Divisions. DD&A expense decreased $0.06 per Mcfe in the first three quarters of 2012, when compared to the first three quarters of 2011. During the first three quarters of 2012 the DD&A expense per Mcfe decline 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 Energy's Pinedale production, increased percentage of production from the lower cost DD&A pools and impairments taken in the fourth quarter of 2011.

QEP Energy's average production costs (lease operating expense) per Mcfe were 2% lower in the third quarter of 2012 compared to the third quarter of 2011. During the first three quarters of 2012, average production costs per Mcfe were flat compared to the first three quarters of 2011. The following table presents average production cost, excluding production taxes for QEP Energy by region on a units of production basis:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Change	2012	2011	Change
	(per Mcfe)					
Northern Region	$0.61	$0.57	$0.04	$0.59	$0.59	$—
Southern Region	0.44	0.51	(0.07)	0.48	0.48	—
Average production cost	0.53	0.54	(0.01)	0.53	0.53	—

Lease operating expense per Mcfe decreased $0.01 during the third quarter ended September 30, 2012, when compared to the third quarter of 2011. The decrease in the third quarter of 2012 lease operating expense is primarily due to a $0.07 per Mcfe decrease in the Southern Region, which was mostly offset by a $0.04 per Mcfe increase in the Northern Region. The Southern Region decrease was a result of an 3% increase in production and a 10% decrease in lease operating expenses. The decrease in lease operating expenses in the Southern Region was driven primarily by decreases in maintenance and repairs. The Northern Region increase was driven by a 39% increase in lease operating expenses, partially offset by a 30% increase in production. Lease operating expense increase in the Northern Region was primarily the result of higher water disposal costs and increases in trucking, chemical, labor and pumper costs. Lease operating expense per Mcfe was flat for the first three quarters of 2012 compared to the 2011 first three quarters. For additional information regarding the variances in production and lease operating expenses, see "Production" and "Operating Expenses" discussions earlier in this Form 10-Q.

Natural gas, oil and NGL transportation and other handling costs per Mcfe were 14% higher in the third quarter of 2012 than in the third quarter of 2011. During the first three quarters of 2012, natural gas, oil and NGL transportation and other handling costs per Mcfe were 9% higher than in the first three quarters of 2011. The per Mcfe increase in both the three and nine months ended September 30, 2012, relates to NGL sale agreements at Mont Belvieu, Texas, and the related transportation and processing of NGL's, which were effective beginning with the startup of the Blacks Fork II plant in the third quarter of 2011.

G&A expense increased $0.06 per Mcfe in the three months ended September 30, 2012, and increased $0.05 per Mcfe in the nine months ended September 30, 2012. The per Mcfe increases in the three and nine months ended September 30, 2012, were the result of higher total G&A expenses in the three and nine months ended September 30, 2012, partially offset by increased production during the same periods. The increased G&A expenses for the period ended September 30, 2012 were driven by increased headcount and the annual compensation program, increases in professional and outside services, increased stock-based compensation expense and expenses incurred in the current year for restructuring costs. See Note 8 – “Restructuring Costs” of this form 10-Q for additional information regarding restructuring costs.

Allocated interest expense per Mcfe increased $0.01 in the three months ended September 30, 2012, but was flat in the nine months ended September 30, 2012. The increase in the three months ended September 30, 2012, was primarily due to an increase in allocated interest expense resulting from higher debt levels.

In most states in which QEP Energy operates, QEP pays production taxes based on a percentage of field-level revenue, except in Louisiana, where severance taxes are volume-based. Production taxes per Mcfe decreased by $0.10 during the three and nine months ended September 30, 2012, because of lower field-level natural gas, oil and NGL prices.

QEP Energy Operating Regions

The following table presents operated and non-operated well completions (excluding completions from the Acquisition) for the three and nine months ended September 30, 2012:

	Operated Completions				Non-operated Completions			
	Three Months Ended September 30, 2012		Nine Months Ended September 30, 2012		Three Months Ended September 30, 2012		Nine Months Ended September 30, 2012	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Northern Region								
Pinedale	35	26.4	86	62.8	—	—	—	—
Uinta Basin	10	9.2	36	33.5	49	0.1	181	0.5
Legacy	9	7.9	18	15.2	17	1.4	66	3.7
Southern Region								
Haynesville/Cotton Valley	—	—	29	16.7	1	0.1	7	0.8
Midcontinent	6	5.2	19	15.1	35	4.6	96	11.5

The following table presents operated and non-operated wells drilling and waiting on completion (including wells drilling and wells waiting on completion from the Acquisition) at September 30, 2012:

	Operated				Non-operated			
	Drilling		Waiting on completion		Drilling		Waiting on completion	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Northern Region								
Pinedale	27	18.1	44	28.0	—	—	—	—
Uinta Basin	4	4.0	2	1.6	—	—	—	—
Legacy	13	11.1	10	7.6	15	0.7	22	3.6
Southern Region								
Haynesville/Cotton Valley	—	—	5	2.4	—	—	1	—
Midcontinent	4	3.1	8	8.0	12	0.3	40	1.7

Northern Region

Pinedale Division

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 17,900 acre (gross) Pinedale leasehold. 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. On March 13, 2012, the WOGCC approved five-acre density drilling for Lance Pool wells on approximately 7,200 additional gross acres. The area approved for increased density corresponds to the currently estimated economic productive limits of QEP Energy core acreage in the field. 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 1,000 additional wells will be required to fully develop its Pinedale acreage on a combination of 5 and 10-acre density. At September 30, 2012, QEP Energy had six operated rigs drilling in the Pinedale Anticline.

Uinta Basin Division

The majority of Uinta Basin proved reserves are found in a series of vertically stacked, laterally discontinuous reservoirs at depths of 4,500 feet to deeper than 18,000 feet. QEP Energy owns working interests in approximately 253,800 net leasehold acres in the Uinta Basin. QEP Energy had three operated rigs drilling in the Uinta Basin at September 30, 2012, two of which are targeting the Lower Mesaverde Formation productive fairway in the Red Wash Unit, in which QEP holds 32,300 net acres, and the other drilling various vertical and horizontal oil targets.

Legacy Division

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 Legacy Division. Exploration and development activity in the three and nine months ended September 30, 2012, includes wells in the Williston Basin in North Dakota, and the Greater Green River and Powder River Basins in Wyoming.

During the third quarter of 2012, QEP Energy closed on the previously discussed Acquisition of 27,600 net acres of producing leaseholds in the Williston Basin. Including the recently acquired properties, QEP has approximately 117,000 net acres of leasehold 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 September 30, 2012, QEP Energy had five operated rigs drilling in the project area.

Southern Region

Haynesville/Cotton Valley Division

QEP Energy has approximately 50,700 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 since the 1990's. As of September 30, 2012, due to depressed natural gas prices QEP Energy did not have any operated rigs drilling in the project area.

Midcontinent Division

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 western Oklahoma and the Texas Panhandle.

QEP Energy has approximately 76,000 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 September 30, 2012, QEP Energy had two operated rigs drilling in the Woodford/Cana play.

QEP Energy has approximately 35,000 net acres of Granite Wash/Atoka Wash 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 September 30, 2012, QEP Energy had one rig drilling in oil plays in the Texas Panhandle.

QEP Field Services

QEP Field Services, which provides gas gathering and processing services, generated net income of $28.7 million in the third quarter of 2012, compared to $42.0 million in the same period of 2011. During the first three quarters of 2012 QEP Field Services net income decreased 6% to $107.4 million compared to $114.2 million in the first three quarters of 2011. The decrease in net income during the third quarter of 2012 was the result of lower processing and gathering margins. During the first three quarters of 2012, gathering margins were lower than the 2011 comparable period, however, processing margins increased slightly during the first three quarters of 2012. Gathering margins were lower during the first three quarters of 2012 as the result of decreased other gathering revenue due to the elimination of a short-term, third-party interruptible processing agreement. The short-term processing arrangement was in effect during the first three quarters of 2011, before the expansion of the Blacks Fork processing plant was put into service during the third quarter of 2011. Processing margins were lower in the third quarter of 2012 because of lower keep-whole processing margins, however, during the first three quarters of 2012 the decrease in the keep-whole margin was more than offset by increases in fee-based processing revenues.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Change	2012	2011	Change
	(in millions)					
Revenues						
NGL sales	$28.9	$44.1	$(15.2)	$112.7	$119.9	$(7.2)
Processing (fee based)	18.2	15.4	2.8	51.8	37.6	14.2
Other processing fees	5.4	1.7	3.7	8.4	1.7	6.7
Gathering	43.9	41.9	2.0	131.6	120.0	11.6
Other gathering	8.0	16.5	(8.5)	28.6	59.2	(30.6)
Purchased gas, oil and NGL sales	5.3	—	5.3	9.9	—	9.9
Total Revenues	109.7	119.6	(9.9)	343.0	338.4	4.6
Operating expenses						
Purchased gas, oil and NGL expense	4.9	—	4.9	9.0	—	9.0
Processing	4.7	3.1	1.6	12.1	8.9	3.2
Processing plant fuel and shrinkage	8.1	12.5	(4.4)	26.6	34.1	(7.5)
Gathering	9.0	11.0	(2.0)	26.9	35.3	(8.4)
Natural gas, oil and NGL transportation and other handling costs	6.9	2.5	4.4	27.7	4.6	23.1
General and administrative	10.6	6.6	4.0	24.1	22.4	1.7
Taxes other than income taxes	1.7	1.4	0.3	4.6	4.4	0.2
Depreciation, depletion and amortization	15.8	14.0	1.8	47.2	40.7	6.5
Total Operating Expenses	61.7	51.1	10.6	178.2	150.4	27.8
Net gain from asset sales	—	(0.1)	0.1	—	—	—
Operating Income	48.0	68.4	(20.4)	164.8	188.0	(23.2)
Interest and other income	—	—	—	0.1	—	0.1
Income from unconsolidated affiliates	2.3	2.3	—	5.5	4.4	1.1
Realized gains on derivative instruments	1.9	—	1.9	6.3	—	6.3
Unrealized gains on derivative instruments	(2.5)	—	(2.5)	2.0	—	2.0
Interest expense	(3.5)	(3.8)	0.3	(9.4)	(10.4)	1.0
Income before Income Taxes	46.2	66.9	(20.7)	169.3	182.0	(12.7)
Income taxes	(16.5)	(24.0)	7.5	(59.2)	(65.6)	6.4
Net income	29.7	42.9	(13.2)	110.1	116.4	(6.3)
Net income attributable to noncontrolling interest	(1.0)	(0.9)	(0.1)	(2.7)	(2.2)	(0.5)
Net Income Attributable to QEP	$28.7	$42.0	$(13.3)	$107.4	$114.2	$(6.8)

Natural gas, oil and NGL transportation and other handling costs increased $4.4 million and $23.1 million during the three and nine months ended September 30, 2012, respectively. The increases in both periods were primarily due to transportation costs relating to the Blacks Fork II plant, placed into service in the third quarter of 2011, and the related transportation and ultimate sale of additional NGL's at Mont Belvieu, Texas.

General and administrative expenses increased by $4.0 million during the third quarter of 2012 and increased $1.7 million

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during the first three quarters of 2012. The increase in G&A costs during the current period was primarily due to increases in headcount and related compensation costs, increase in the mark-to-market value of the deferred compensation wrap plan, and higher professional and outside services.

See “Gathering” and “Processing” sections, as appearing earlier, for additional discussion of the significant changes in QEP Field Services comparative financial statements.

QEP Marketing and Other

QEP Marketing, which markets affiliate and third-party natural gas and oil, and owns and operates a gas storage facility, generated a net loss of $5.6 million in the three months ended September 30, 2012, a $6.8 million decrease over the $1.2 million of income in the three months ended September 30, 2011 from lower marketing margins and unrealized losses from derivative contracts. During the nine months ended September 30, 2012, net income decreased $12.7 million, or 249%, due primarily to lower marketing volumes and margins combined with unrealized losses from derivative contracts. During the three and nine months ended September 30, 2012, QEP Marketing had a loss on resale gas, oil and NGL of $1.8 million and $7.0 million, respectively, related to fulfillment of firm transportation contract commitments.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Change	2012	2011	Change
	(in millions)					
Revenues						
Purchased gas, oil and NGL sales	$234.9	$293.1	$(58.2)	$674.7	$865.3	$(190.6)
Other	1.4	1.1	0.3	5.3	6.2	(0.9)
Total Revenues	236.3	294.2	(57.9)	680.0	871.5	(191.5)
Operating expenses						
Purchased gas, oil and NGL expense	236.7	292.0	(55.3)	681.7	862.4	(180.7)
Gathering, processing and other	0.1	0.4	(0.3)	0.8	1.1	(0.3)
General and administrative	0.5	0.2	0.3	0.6	1.8	(1.2)
Production and property taxes	0.1	—	0.1	0.2	0.2	—
Depreciation, depletion and amortization	0.9	0.6	0.3	2.5	1.7	0.8
Total Operating Expenses	238.3	293.2	(54.9)	685.8	867.2	(181.4)
Net gain from asset sales	—	0.1	(0.1)	—	—	—
Operating (Loss) Income	(2.0)	1.1	(3.1)	(5.8)	4.3	(10.1)
Realized (loss) gain on derivative instruments	(1.0)	—	(1.0)	3.1	—	3.1
Unrealized loss on derivative instruments	(3.7)	—	(3.7)	(7.1)	—	(7.1)
Interest and other income	28.4	25.0	3.4	81.1	74.2	6.9
Loss on extinguishment of debt	—	(0.7)	0.7	(0.6)	(0.7)	0.1
Interest expense	(30.8)	(23.5)	(7.3)	(83.4)	(70.0)	(13.4)
(Loss) Income before Income Taxes	(9.1)	1.9	(11.0)	(12.7)	7.8	(20.5)
Income tax benefit (provision)	3.5	(0.7)	4.2	5.1	(2.7)	7.8
	$(5.6)	$1.2	$(6.8)	$(7.6)	$5.1	$(12.7)

Net (Loss) Income Attributable
to QEP

LIQUIDITY AND CAPITAL RESOURCES

QEP seeks to fund its development projects by employing a capital structure and financing strategy to provide sufficient liquidity to withstand commodity price swings. As part of this strategy QEP funds long-term capital intensive development projects while maintaining the ability to employ an exploration program, execute acquisitions and maintain an appropriate debt rating. In addition, QEP maintains a commodity price derivative strategy to reduce commodity price volatility and to provide certainty to cash flows and operations.

QEP funds its operations, capital expenditures and working capital requirements with cash flow from its operating activities and borrowings under its credit facilities. Periodically, QEP's access to debt and capital markets and sales of non-strategic properties will provide additional liquidity. The Company believes cash flow from operations, cash-on-hand and availability under its Credit Facility will be sufficient to fund the Company's planned capital expenditures and operating expenses during the next 12 months. To the extent actual operating results differ from the Company's estimates, QEP's liquidity could be adversely affected.

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

	September 30, 2012		December 31, 2011	
	(in millions, except %)			
Cash and cash equivalents	$—		$—	
Amount available under the Credit Facility [(1)]	831.9		893.5	
Total liquidity	$831.9		$893.5	
Total debt [(2)]	$3,180.7		$1,679.4	
Total common shareholders' equity	3,329.0		3,301.5	
Ratio of debt to total capital [(3)]	49	%	34	%

(1) See discussion of Credit Facility below. Includes outstanding letters of credit of $4.1 million.
(2) Includes all outstanding long-term debt which is discussed in detail below. At September 30, 2012, debt levels were higher than at December 31, 2011, primarily due to the Acquisition.
(3) Defined as total debt divided by the sum of total debt plus common shareholders' equity.

Credit Facility

QEP's revolving credit facility agreement, which matures in August 2016, provides for loan commitments of $1.5 billion from a syndicate of financial institutions. The Credit Facility provides for borrowings at short-term interest rates and contains customary covenants and restrictions. The credit facility 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. QEP's weighted-average interest rate on borrowings from its Credit Facility was 2.05% during the first three quarters of 2012. At September 30, 2012, QEP was in compliance with the debt covenants under the credit agreement. At October 26, 2012, QEP had $661.5 million outstanding under its Credit Facility and $4.1 million of letters of credit issued.

Term Loan

During the second quarter of 2012, the Company entered into a $300.0 million Term Loan with a group of financial institutions. The Term Loan agreement provides for borrowings at short-term interest rates and contains covenants, restrictions and interest rates that are substantially the same as the Company's Credit Facility. The Term Loan matures in April of 2017, and the maturity date may be extended one year with the agreement of the lenders. The proceeds from the Term Loan were used to pay down the Company's Credit Facility and general corporate purposes. During the third quarter of 2012, QEP's weighted-average interest rate on the Term Loan was 2.02%. In conjunction with the Term Loan, QEP entered into interest rate swap contracts with a combined notional principal amount of $300.0 million which will mature in March 2017. Under the swap contracts, QEP pays 1.07% for the life of the swaps and receives one-month LIBOR. The interest rate at September 30, 2012 under the Term Loan is one-month LIBOR, plus 1.75% (the Applicable Margin) which, when combined with the fixed interest rate swaps, results in an effective rate of 2.82% for borrowings under the Term Loan. To the extent that the Applicable Margin under the Term Loan changes, the effective fixed rate paid for borrowings under the Term Loan will change.

Senior Notes

During the third quarter of 2012, the Company completed an offering of $650.0 million in aggregate principal amount of 5.25% senior notes due in May 2023. The proceeds from the 2023 Senior Notes were used to finance a portion of the Acquisition. In addition, during the first quarter of 2012, the Company completed an offering of $500.0 million in aggregate principal amount of 5.375% senior notes due in October 2022. The proceeds from the 2022 Senior Notes were used to repay indebtedness under the Company's Credit Facility. In the second quarter of 2012, the Company purchased $6.7 million of its Senior Notes outstanding.

The Company's senior notes outstanding as of September 30, 2012, totaled $2,221.8 million principal amount and are comprised of six issuances as follows:

- $176.8 million 6.05% Senior Notes due September 2016

- $134.0 million 6.80% Senior Notes due April 2018

- $136.0 million 6.80% Senior Notes due March 2020

- $625.0 million 6.875% Senior Notes due March 2021

- $500.0 million 5.375% Senior Notes due October 2022

- $650.0 million 5.25% Senior Notes due May 2023

Cash Flow 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.

Net cash provided by operating activities increased 2% during the first three quarters of 2012, when compared to the first three quarters of 2011 due to higher noncash adjustments to net income and an increase in the source of cash from operating assets and liabilities. Noncash adjustments to net income consisted primarily of depreciation, depletion and amortization; abandonment and impairment charges; unrealized gains on derivative contracts; and changes in deferred income taxes. Changes in operating assets and liabilities were a source of cash in the first three quarters of 2012, primarily due to a decrease in accounts receivable offset by a decrease in accounts payable. Changes in operating assets and liabilities driving a source of cash in the first three quarters of 2011 were increases in accounts payable, offset by increases in accounts receivable. Net cash provided from operating activities is presented below:

	Nine Months Ended September 30,		
	2012	2011	Change
	(in millions)		
Net income	$154.1	$269.7	$(115.6)
Noncash adjustments to net income	763.4	673.8	89.6
Changes in operating assets and liabilities	54.5	12.2	42.3
Net cash provided from operating activities	$972.0	$955.7	$16.3

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Cash Flow from Investing Activities

A comparison of capital expenditures for the first three quarters of 2012 and 2011 and a forecast for calendar year 2012 are presented in the table below:

	Nine Months Ended September 30,			Current Forecast Twelve Months Ended [1]	Prior Forecast Twelve Months Ended [2]
	2012	2011	Change	December 31, 2012	December 31, 2012
	(in millions)				
QEP Energy	$2,391.0	$939.4	$1,451.6	$1,370.0	$1,320.0
QEP Field Services	141.2	68.1	73.1	170.0	170.0
QEP Marketing	0.7	0.2	0.5	1.0	1.0
Corporate	5.7	3.2	2.5	9.0	9.0
Total accrued capital expenditures	2,538.6	1,010.9	1,527.7	1,550.0	1,500.0
Change in accruals	(97.6)	(12.5)	(85.1)	—	—
Total cash capital expenditures	$2,441.0	$998.4	$1,442.6	$1,550.0	$1,500.0

(1) Represents the upper end of the most recent guidance and excludes approximately $1.4 billion of properties acquired in the Acquisition.

(2) Forecast as reported in the 2012 Second Quarter Report on Form 10-Q, filed on July 31, 2012.

During the first three quarters of 2012 capital expenditures on a cash basis increased 144% to $2,441.0 million, compared to $998.4 million during the first three quarters of 2011. The increase of $1,442.6 million cash capital expenditures during the first three quarters of 2012 was the result of QEP Energy's approximate $1.4 billion Acquisition. Approximately $2,302.8 million of the total 2012 cash capital expenditures was invested in QEP Energy, including $902.8 million in drilling and completion and other expenditures and $1,400.0 million in property acquisitions. QEP Field Services first three quarters of 2012 cash capital expenditures of $131.8 million were invested to expand capacity at the Company’s gathering, processing and treating facilities, including the construction of a new 150 MMcfd cryogenic gas processing plant in the Uinta Basin.

QEP Energy capital investment, on an accrual basis, in the first three quarters of 2012 increased $1,451.6 million over the first three quarters of 2011 due to increased capital expenditures in the Legacy Division (which was higher primarily due to the Acquisition), offset by lower capital expenditures in the Haynesville Division (approximately 75% lower) due to the reduced drilling program as capital was allocated out of the dry-gas Haynesville play into higher return oil and liquids-rich natural gas drilling programs.

QEP Field Services capital investment increased $73.1 million, on an accrual basis, in the first three quarters of 2012 compared to the first three quarters of 2011 due to the projects directed to grow the midstream business including the construction of a new 150 MMcfd fee-based cryogenic gas processing plant in the Uinta Basin and the 10,000 Bbl/d expansion to the NGL fractionators located at the Blacks Fork processing complex.

At September 30, 2012, forecasted capital investments, excluding the approximate $1.4 billion Acquisition, for 2012 is expected to be $1,550.0 million, comprised of $1,370.0 million at QEP Energy, $170.0 million at QEP Field Services, and $10.0 million for QEP Resources and QEP Marketing. For the remainder of 2012, QEP intends to fund capital expenditures with cash flow from operating activities, and, if needed, borrowings under its revolving credit facility. As a result of the continued spread between crude oil and natural gas prices, 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, Uinta Basin Red Wash Mesaverde, and oil-directed horizontal drilling in the Bakken, Powder River Basin and Midcontinent, for the remainder of 2012. QEP Energy has allocated approximately 93% of its forecasted 2012 drilling and completion capital expenditure budget to crude oil and liquids-rich natural gas projects in its portfolio. QEP plans to invest a total of approximately $170.0 million in capital expenditures during 2012 to grow its midstream business, including the construction of a new 150 MMcfd fee-based cryogenic gas processing plant in the Uinta Basin (expected to be completed in early 2013) as well as a new 10,000 Bbl/d expansion of the NGL fractionator located at the Blacks Fork processing complex (expected to be completed in the second half of 2013). QEP Resources plans to invest approximately $9.0 million in capital expenditures related to corporate activities, primarily the implementation of a new Enterprise Resource Planning system. 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.

Cash Flow from Financing Activities

In the first three quarters of 2012, net cash proceeds from financing activities was $1,463.7 million compared to $35.3 million in the first three quarters of 2011. During the first three quarters of 2012, QEP completed offerings of $650.0 million and $500.0 million of senior notes and entered into a $300.0 million Term Loan. QEP had borrowings from the Credit Facility of $933.5 million and repayments on the Credit Facility of $876.0 million. In addition, QEP retired $6.7 million of its outstanding senior notes.

At September 30, 2012, long-term debt consisted of $664.0 million outstanding under the Credit Facility, $300.0 million under the Term Loan and $2,221.8 million in senior notes (including $5.1 million of net original issue discount).

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

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. The Company's risk management policies provide for the use of derivative instruments to manage this risk. However, these same arrangements typically limit future gains from favorable price movements. The types of commodity derivative instruments utilized by the Company include fixed-price swaps and costless collars. The volume of commodity derivative instruments utilized by the Company may vary from year-to-year. 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 September 30, 2012, QEP held commodity price derivative contracts totaling 147.7 million MMBtu of natural gas, 6.8 million barrels of oil, and 15.5 million gallons of NGL. At December 31, 2011, the QEP derivative contracts covered 213.0 million MMBtu of natural gas, 2.0 million barrels of oil, and 53.9 million gallons of NGL.

The following table presents open 2012 derivative positions as of October 26, 2012:

QEP Energy Commodity Derivative Positions

Year	Type of Contract	Index	Total Volumes	Swaps Average price per unit	Collars Floor price	Ceiling price
			(in millions)			
Natural gas sales			(MMBtu)			
2012	Swap	NYMEX	19.3	$4.72		
2012	Swap	IFPEPL [1]	1.8	$4.70		
2012	Swap	IFNPCR [2]	22.1	$4.67		
2012	Swap	IFCNPTE [3]	2.8	$2.66		
2013	Swap	NYMEX	40.2	$3.74		
2013	Swap	IFNPCR [2]	65.7	$5.66		
2014	Swap	NYMEX	18.3	$4.21		
Oil sales			(Bbls)			
2012	Swap	NYMEX WTI	1.3	$97.42		
2012	Collar	NYMEX WTI	0.4		$87.50	$115.36
2013	Swap	NYMEX WTI	5.1	$98.48		
2014	Swap	NYMEX WTI	1.8	$92.72		
NGL sales			(Gals)			
2012	Swap	Mt. Belvieu Ethane	3.9	$0.64		
2012	Swap	Mt. Belvieu Propane	5.8	$1.28		

QEP Field Services Commodity Derivative Positions

Year	Type of Contract	Index	Total Volumes	Average Swap price per gallon
			(in millions)	
NGL sales			(Gals)	
2012	Swap	Mt. Belvieu Ethane	3.9	$0.64
2012	Swap	Mt. Belvieu Propane	1.9	$1.28

QEP Marketing Commodity Derivative Positions

Year	Type of Contract	Index	Total Volumes	Average Swaps price per MMBtu
			(in millions)	
Natural gas sales			(MMBtu)	
2012	Swap	IFNPCR	2.3	$3.87
2013	Swap	IFNPCR	3.9	$3.79
Natural gas purchases			(MMBtu)	
2012	Swap	IFNPCR	2.0	$2.92
2013	Swap	IFNPCR	0.1	$2.59

Changes in the fair value of derivative contracts from December 31, 2011 to September 30, 2012, are presented below:

	Commodity derivative contracts
	(in millions)
Net fair value of gas and oil derivative contracts outstanding at December 31, 2011	$395.9
Contracts settled	(302.6)
Change in gas and oil prices on futures markets	113.3
Contracts added	15.7
Net fair value of gas, oil and NGL derivative contracts outstanding at September 30, 2012	$222.3

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

	September 30, 2012
	(in millions)
Net fair value - asset (liability)	$222.3
Fair value if market prices of gas, oil and NGL and basis differentials decline by 10%	348.8
Fair value if market prices of gas, oil and NGL and basis differentials increase by 10%	94.8

Utilizing the actual derivative contractual volumes, a 10% increase in underlying commodity prices would reduce the fair value of these instruments by $127.5 million, while a 10% decrease in underlying commodity prices would increase the fair value of these instruments by $126.5 million as of September 30, 2012. However, a gain or loss eventually would be substantially offset by the actual sales value of the physical production covered by the derivative instruments. For additional information regarding the Company’s commodity derivative transactions, see Note 7 – Derivative Contracts under Part I, Item 1 of this Form 10-Q.

Interest-Rate Risk Management

The Company’s ability to borrow and the rates offered by lenders can be adversely affected by illiquid credit markets as described in the risk factors in Part I, Item 1A of the Company’s Annual Report on Form 10-K for the year ended December 31, 2011. The Company’s Credit Facility has a floating interest rate which expose QEP to interest rate risk. At September 30, 2012, the Company had $664.0 million outstanding under the Credit Facility. If interest rates were to increase or decrease 10% over the nine months ended September 30, 2012, at our average level of borrowing for those same periods, our interest expense would increase or decrease by $0.5 million for the nine months ended September 30, 2012, or less than 1% in each period. The remaining $2,221.8 million of the Company’s debt is fixed rate Senior Notes that are not subject to interest rate movements.

The Company’s Term Loan has a floating interest rate which exposes QEP to interest rate risk. At September 30, 2012, the Company had $300.0 million outstanding under the Term Loan. During the second quarter of 2012, QEP entered into interest rate swap contracts, with an aggregate notional amount of $300.0 million, to minimize the interest rate volatility risk associated with its $300.0 million senior, unsecured term loan agreement. QEP pays a fixed interest rate and receives a floating interest rate indexed to the one-month LIBOR. At September 30, 2012, the fair value of the interest rate swaps was a derivative liability balance of $6.7 million. A 50 basis point decrease would cause the fair value of the interest rate swaps to decrease by $6.0 million while a 50 basis point increase would cause the fair value of the interest rate swaps to increase by $6.5 million. For additional information regarding the Company’s debt instruments, see Note 9 – Debt under Part I, Item 1 of this Form 10-Q.

Forward-Looking Statements

This quarterly report contains 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. They use words such as “anticipate,” “estimate,” “expect,” “project,” “intend,” “plan,” “believe,” and other words and terms of similar meaning in connection with a discussion of future operating or financial performance. Forward-looking statements include statements relating to, among other things:

- QEP’s growth strategies;
- natural gas, oil and NGL prices and factors affecting the volatility of such prices;
- plans to drill or participate in wells and to defer completion of wells;
- future expenses and operating costs;
- the outcome of contingencies such as legal proceedings;
- expected contributions related to the Company’s pension plans;
- results from planned drilling operations and production operations;
- amount and allocation of forecasted capital expenditures and plans for funding capital expenditures and operating expenses;
- the amount and timing of the settlement of derivative contracts;
- incurrence of unrealized derivative gains and losses;
- expected mix of revenues from the Company’s gathering business;
- impact on earnings from discontinuing hedge accounting;
- 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 and the availability to the Company of the end-user exemption under Title VII of the Dodd-Frank Act;
- payment of dividends;
- plans to hedge a portion of forecasted production;
- outcome of litigation;
- potential for future asset impairments;

- estimated future purchase accounting adjustments;
- maintaining an appropriate debt rating; and
- acquisition plans.

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 the Company's Annual Report on Form 10-K for the year ended December 31, 2011
- changes in natural gas, oil and NGL prices;
- general economic conditions, including the performance of financial markets and interest rates;
- global geopolitical and macroeconomic factors;
- drilling results;
- shortages of oilfield equipment, services and personnel;
- permitting delays;
- operating risks such as unexpected drilling conditions;
- weather conditions;
- changes in maintenance and construction costs, including possible inflationary pressures;
- the availability and cost of debt financing;
- changes in laws or regulations, including the implementation of the Dodd-Frank Act and initiatives related to drilling and completion techniques, including hydraulic fracturing;
- actions, or inaction, by federal, state, local or tribal governments;
- derivatives and hedging activities;
- liabilities from litigation; 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 quarterly report, in other documents, or on the website to reflect future events or circumstances. All such statements are expressly qualified by this cautionary statement.

ITEM 4. 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 September 30, 2012. Based on such evaluation, such officers have concluded that, as of September 30, 2012, the Company's disclosure controls and procedures are designed and effective to ensure that information required to be included in the Company's reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms and that information 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 during the quarter ended September 30, 2012, that have materially affected, or that are reasonably likely to materially affect, the Company’s internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Information regarding legal proceedings is set forth in Note 10 - Contingencies to the Company's consolidated financial statements included in Item 1 of Part I of this Quarterly Report on Form 10-Q and is incorporated herein by reference.

ITEM 1A. RISK FACTORS

Risk factors relating to the Company are set forth in its Annual Report on Form 10-K for the year ended December 31, 2011. No material changes, except as noted below, to such risk factors have occurred during the nine months ended September 30, 2012.

Our ability to produce crude oil and natural gas economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations or are unable to dispose of, or recycle the water we use at a reasonable cost and in accordance with applicable environmental rules. The hydraulic fracturing process on which we depend to produce commercial quantities of crude oil and natural gas from many reservoirs requires the use and disposal of significant quantities of water. Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations at a reasonable cost, could adversely impact our operations.

Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our 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 our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

QEP had no unregistered sales of equity during the third quarter of 2012.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

None.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

The following exhibits are being filed as part of this report:

Exhibit No.	Exhibits
10.1	Purchase and Sale Agreement, dated as of August 23, 2012, by and among QEP Energy Company, as purchaser, and Helis Oil & Gas Company, L.L.C., as seller.
10.2	Purchase and Sale Agreement, dated August 23, 2012, by and among QEP Energy Company, as purchaser, and Black Hills Exploration and Production, Inc., Unit Petroleum Company, Sundance Energy, Inc., Highline Exploration, Inc., Houston Energy, L.P., Nisku Royalty, LP, Empire Oil Company and Kent M. Lynch, as sellers.
31.1	Certification signed by C. B. Stanley, QEP Resources, Inc.'s 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.'s Chief Financial Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification signed by C. B. Stanley and Richard J. Doleshek, QEP Resources, Inc.'s Chief Executive Officer and Chief Financial Officer, 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

SIGNATURES

Pursuant to the requirements 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.

	QEP RESOURCES, INC. (Registrant)
October 30, 2012	/s/ C. B. Stanley C. B. Stanley, Chairman, President and Chief Executive Officer
October 30, 2012	/s/ Richard J. Doleshek Richard J. Doleshek, Executive Vice President, Chief Financial Officer and Treasurer

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