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

FORM 10-Q

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

For the quarterly period ended June 30, 2014

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

For the transition period from ______ to ______

Commission File Number: **001-34778**

QEP RESOURCES, INC.

(Exact name of registrant as specified in its charter)

STATE OF DELAWARE	**87-0287750**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

1050 17th Street, Suite 800, Denver, Colorado 80265
(Address of principal executive offices)

Registrant's telephone number, including area code (303) 672-6900

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

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

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

At June 30, 2014, there were 180,091,487 shares of the registrant's common stock, $0.01 par value, outstanding.

QEP Resources, Inc.
Form 10-Q for the Quarter Ended June 30, 2014

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PART I. FINANCIAL INFORMATION

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	**2014**	2013
REVENUES	(in millions, except per share amounts)			
Gas sales	**$ 215.1**	$ 218.1	**$ 437.6**	$ 415.7
Oil sales	**358.8**	208.3	**647.5**	402.5
NGL sales	**92.9**	75.3	**194.0**	143.7
Gathering, processing and other	**34.0**	42.6	**78.4**	88.2
Purchased gas, oil and NGL sales	**235.9**	206.7	**463.1**	397.4
Total Revenues	**936.7**	751.0	**1,820.6**	1,447.5
OPERATING EXPENSES				
Purchased gas, oil and NGL expense	**235.7**	207.0	**460.0**	403.8
Lease operating expense	**57.5**	43.5	**112.8**	82.4
Gas, oil and NGL transportation and other handling costs	**54.3**	37.3	**97.7**	71.3
Gathering, processing and other	**24.8**	23.5	**50.6**	44.1
General and administrative	**64.2**	40.9	**120.8**	86.9
Production and property taxes	**56.1**	39.3	**105.4**	75.2
Depreciation, depletion and amortization	**249.7**	249.8	**489.9**	504.0
Exploration expenses	**1.7**	2.6	**3.9**	7.7
Impairment	**1.5**	0.2	**3.5**	0.2
Total Operating Expenses	**745.5**	644.1	**1,444.6**	1,275.6
Net gain (loss) from asset sales	**(201.0)**	100.4	**(198.6)**	100.2
OPERATING INCOME (LOSS)	**(9.8)**	207.3	**177.4**	272.1
Realized and unrealized gains (losses) on derivative contracts (See Note 8)	**(88.0)**	114.0	**(168.9)**	79.4
Interest and other income	**0.8**	3.1	**3.7**	5.1
Income from unconsolidated affiliates	**1.2**	1.6	**3.4**	2.9
Interest expense	**(45.7)**	(41.4)	**(88.2)**	(80.8)
INCOME (LOSS) BEFORE INCOME TAXES	**(141.5)**	284.6	**(72.6)**	278.7
Income tax (provision) benefit	**54.2**	(104.8)	**30.8**	(102.6)
NET INCOME (LOSS)	**(87.3)**	179.8	**(41.8)**	176.1
Net income attributable to noncontrolling interest	**(5.0)**	(1.4)	**(10.8)**	(2.0)
NET INCOME (LOSS) ATTRIBUTABLE TO QEP	**$ (92.3)**	$ 178.4	**$ (52.6)**	$ 174.1
Earnings (Loss) Per Common Share Attributable to QEP				
Basic	**$ (0.51)**	$ 0.99	**$ (0.29)**	$ 0.97
Diluted	**$ (0.51)**	$ 0.99	**$ (0.29)**	$ 0.97
Weighted-average common shares outstanding				
Used in basic calculation	**180.1**	179.3	**179.9**	179.1
Used in diluted calculation	**180.1**	179.5	**179.9**	179.4
Dividends per common share	**$ 0.02**	$ 0.02	**$ 0.04**	$ 0.04

See notes accompanying the condensed consolidated financial statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	**2014**	2013
	(in millions)			
Net income (loss)	**$ (87.3)**	$ 179.8	**$ (41.8)**	$ 176.1
Other comprehensive income (loss), net of tax:				
Reclassification of previously deferred derivative gains[1]	**—**	(20.6)	**—**	(40.7)
Pension and other postretirement plans adjustments:				
Amortization of net actuarial loss [2]	**0.1**	0.3	**0.2**	0.7
Amortization of prior service cost [3]	**0.8**	0.9	**1.7**	1.7
Total pension and other postretirement plans adjustments	**0.9**	1.2	**1.9**	2.4
Other comprehensive income (loss)	**0.9**	(19.4)	**1.9**	(38.3)
Comprehensive income (loss)	**(86.4)**	160.4	**(39.9)**	137.8
Comprehensive income attributable to noncontrolling interests	**(5.0)**	(1.4)	**(10.8)**	(2.0)
Comprehensive income (loss) attributable to QEP	**$ (91.4)**	$ 159.0	**$ (50.7)**	$ 135.8

[1] Presented net of income tax benefit of $12.2 million and $24.1 million during the three and six months ended June 30, 2013.
[2] Presented net of income tax expense of $0.1 million and $0.2 million during the three and six months ended June 30, 2014 and $0.3 million and $0.5 million during the three and six months ended June 30, 2013, respectively.
[3] Presented net of income tax expense of $0.5 million and $1.0 million during the three and six months ended June 30, 2014 and $0.5 million and $1.0 million during the three and six months ended June 30, 2013, respectively.

See notes accompanying the condensed consolidated financial statements.

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

	June 30, 2014	December 31, 2013
ASSETS	(in millions)	
Current Assets		
Cash and cash equivalents	$ **702.3**	$ 11.9
Accounts receivable, net	**555.7**	408.5
Fair value of derivative contracts	**—**	0.2
Gas, oil and NGL inventories, at lower of average cost or market	**8.6**	13.4
Deferred income taxes - current	**50.7**	30.6
Prepaid expenses and other	**66.7**	54.4
Total Current Assets	**1,384.0**	519.0
Property, Plant and Equipment (successful efforts method for oil and gas properties)		
Proved properties	**11,231.2**	11,571.4
Unproved properties	**1,120.1**	665.1
Midstream field services	**1,735.2**	1,698.1
Marketing and resources	**92.1**	85.5
Material and supplies	**66.0**	59.0
Total Property, Plant and Equipment	**14,244.6**	14,079.1
Less Accumulated Depreciation, Depletion and Amortization		
Exploration and production	**4,680.5**	4,930.9
Midstream field services	**441.1**	409.7
Marketing and resources	**26.7**	22.1
Total Accumulated Depreciation, Depletion and Amortization	**5,148.3**	5,362.7
Net Property, Plant and Equipment	**9,096.3**	8,716.4
Investment in unconsolidated affiliates	**36.7**	39.0
Fair value of derivative contracts	**1.7**	1.0
Restricted Cash	**—**	50.0
Other noncurrent assets	**44.1**	51.4
TOTAL ASSETS	$ **10,562.8**	$ 9,376.8
LIABILITIES AND EQUITY		
Current Liabilities		
Checks outstanding in excess of cash balances	$ **5.7**	$ 90.9
Accounts payable and accrued expenses	**692.6**	434.9
Production and property taxes	**65.7**	51.8
Interest payable	**37.1**	37.2
Fair value of derivative contracts	**109.3**	26.7
Total Current Liabilities	**910.4**	641.5
Long-term debt	**3,910.8**	2,997.5
Deferred income taxes	**1,597.6**	1,560.6
Asset retirement obligations	**188.5**	191.8
Fair value of derivative contracts	**16.1**	—
Other long-term liabilities	**113.5**	108.6
Commitments and contingencies (see Note 11)		
EQUITY		
Common stock - par value $0.01 per share; 500.0 million shares authorized; 180.8 million and 179.7 million shares issued, respectively	**1.8**	1.8
Treasury stock - 0.7 million and 0.4 million shares, respectively	**(23.0)**	(14.9)
Additional paid-in capital	**518.0**	498.4
Retained earnings	**2,857.9**	2,917.8
Accumulated other comprehensive loss	**(24.6)**	(26.5)
Total Common Shareholders' Equity	**3,330.1**	3,376.6
Noncontrolling interest	**495.8**	500.2
Total Equity	**3,825.9**	3,876.8
TOTAL LIABILITIES AND EQUITY	$ **10,562.8**	$ 9,376.8

See notes accompanying the condensed consolidated financial statements.

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

	Six Months Ended June 30,	
	2014	2013
	(in millions)	
OPERATING ACTIVITIES		
Net income (loss)	**$ (41.8)**	$ 176.1
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	**489.9**	504.0
Deferred income taxes	**15.8**	121.0
Impairment	**3.5**	0.2
Equity-based compensation	**13.4**	13.2
Amortization of debt issuance costs and discounts	**3.4**	3.1
Net (gain) loss from asset sales	**198.6**	(100.2)
Income from unconsolidated affiliates	**(3.4)**	(2.9)
Distributions from unconsolidated affiliates and other	**6.3**	4.1
Unrealized loss on derivative contracts	**98.2**	1.4
Changes in operating assets and liabilities	**76.4**	(222.1)
Net Cash Provided by Operating Activities	**860.3**	497.9
INVESTING ACTIVITIES		
Property acquisitions	**(949.4)**	(22.0)
Property, plant and equipment, including dry exploratory well expense	**(779.0)**	(719.9)
Proceeds from disposition of assets	**706.3**	143.0
Acquisition deposit held in escrow	**50.0**	—
Net Cash Used in Investing Activities	**(972.1)**	(598.9)
FINANCING ACTIVITIES		
Checks outstanding in excess of cash balances	**(85.2)**	55.8
Long-term debt issued	**300.0**	—
Long-term debt issuance costs paid	**(1.1)**	—
Proceeds from credit facility	**3,151.0**	1,601.0
Repayments of credit facility	**(2,538.0)**	(1,402.5)
Treasury stock repurchases	**(5.5)**	(7.5)
Other capital contributions	**4.1**	2.9
Dividends paid	**(7.3)**	(7.2)
Excess tax (provision) benefit on equity-based compensation	**(0.6)**	1.3
Distribution to noncontrolling interest	**(15.2)**	(3.1)
Net Cash Provided by Financing Activities	**802.2**	240.7
Change in cash and cash equivalents	**690.4**	139.7
Beginning cash and cash equivalents	**11.9**	—
Ending cash and cash equivalents	**$ 702.3**	$ 139.7
Supplemental Disclosures:		
Cash paid for interest, net of capitalized interest	**$ 84.9**	$ 76.7
Cash paid for income taxes	**$ 0.2**	41.5
Non-cash investing activities:		
Change in capital expenditure accrual balance	**$ 26.3**	$ 2.8

See notes accompanying the condensed consolidated financial statements.

Note 1 - Nature of Business

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

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

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

In December 2013, QEP's Board of Directors authorized the Company to develop a plan to separate the business of QEP Field Services, including the Company's interest in QEP Midstream, from QEP. In June 2014, in conjunction with evaluating separation alternatives, QEP Field Services filed a Registration Statement on Form 10 with the U.S. Securities and Exchange Commission in connection with the separation of QEP Field Services into a separate publicly traded company. The separation transaction is expected to close in the second half of 2014.

Shares of QEP’s common stock trade on the New York Stock Exchange (NYSE) 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, including QEP Midstream (see Note 4 - QEP Midstream). The condensed consolidated financial statements also include the accounts of a variable interest entity where the Company is the primary beneficiary of the arrangements. 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 and the year-end balance sheet 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, 2013.

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 six months ended June 30, 2014, are not necessarily indicative of the results that may be expected for the year ending December 31, 2014.

Reclassifications

During the first six months of 2013, QEP presented certain credit facility payments and borrowings on a net basis on the Condensed Consolidated Statements of Cash Flow. These borrowings and payments were reclassified to be presented on a gross basis on the Condensed Consolidated Statements of Cash Flow in order to conform with the current period presentation. This reclassification is entirely within "Financing Activities" and has no effect on other categories or total cash on the Condensed Consolidated Statements of Cash Flows or net income or earnings per share on the Condensed Consolidated Statements of Operations.

New accounting pronouncements

In April 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2014-08, *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity*, which broadened the reporting of discontinued operations to a component of an entity that has operations and cash flows that can be clearly distinguished from the rest of the entity. Under this guidance, to be a discontinued operation, a component or group of components must represent a strategic shift that has (or will have) a major effect on an entity's operations and financial results. The amendments are effective prospectively for reporting periods beginning on or after December 15, 2014 and early adoption is permitted. The Company has chosen not to early adopt and will implement the amendments in the 2015 fiscal year.

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

Note 3 - Acquisitions and Divestitures

Permian Basin Acquisition

On February 25, 2014, QEP Energy acquired oil and gas properties in the Permian Basin of Texas for an aggregate purchase price of $942.1 million, subject to post-closing purchase price adjustments (the Permian Basin Acquisition). The acquired properties consist of approximately 26,500 net acres of producing and undeveloped oil and gas properties and approximately 270 vertical producing wells in the Permian Basin, which created a new core area of operation for QEP Energy. The acquisition was funded with $50.0 million of restricted cash, $300.0 million from the Company's expanded term loan and the remainder was funded from its revolving credit facility.

Concurrent with the Permian Basin Acquisition, QEP entered into a transaction structured as a reverse like-kind exchange in accordance with Section 1031 of the Internal Revenue Code. In connection with this reverse like-kind exchange, QEP assigned the ownership of the Permian Basin oil and gas properties acquired to a variable interest entity. QEP operated the properties pursuant to lease and management agreements with that entity, and had a call option which allowed the Company to terminate the exchange transaction at any time up to August 24, 2014, the expiration date of the exchange. Because the Company was the primary beneficiary of these arrangements, the acquired properties are included in its Condensed Consolidated Balance Sheet as of June 30, 2014, and all revenues earned, expenses incurred, and cash flows related to the properties are included in the Company’s Condensed Consolidated Statements of Operations and Condensed Consolidated Statements of Cash Flows for the three and six months ended June 30, 2014. QEP exercised the call option in connection with certain property divestitures in the second quarter of 2014, as described below under "Divestitures." The lease and management agreements terminated upon the transfer of the acquired properties from the exchange accommodation titleholder to QEP following the exercise of the call option.

The Permian Basin Acquisition meets the definition of a business combination under ASC 805, *Business Combinations*, as it included significant proved properties. QEP allocated the cost of the Permian Basin Acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Revenues of $61.9 million and net income of $14.0 million were generated from the acquired properties from February 25, 2014, to June 30, 2014, and are included in QEP's Condensed Consolidated Statements of Operations. During the six months ended June 30, 2014, QEP Energy incurred acquisition-related costs of $0.6 million which are included in "General and administrative" on the Condensed Consolidated Statements of Operations for the six months ended June 30, 2014. QEP incurred $1.1 million of debt issuance costs associated with increasing the size of term loan borrowings to fund a portion of the acquisition, which are included in "Other noncurrent assets" on the Condensed Consolidated Balance Sheet as of June 30, 2014.

QEP Energy recorded the Permian Basin Acquisition on its Condensed Consolidated Balance Sheet as of June 30, 2014; however, the final purchase price is subject to post-closing purchase price adjustments. The following table presents a summary of the Company's preliminary purchase accounting entries:

		As of June 30, 2014
		(in millions)
Consideration given:		
Cash Consideration	**$**	**945.0**
Consideration receivable		**(2.9)**
Total consideration given	**$**	**942.1**
Amounts recognized for preliminary fair value of assets acquired and liabilities assumed:		
Proved properties	**$**	**472.1**
Unproved properties		**480.9**
Asset retirement obligations		**(9.7)**
Liabilities assumed		**(1.2)**
Total fair value	**$**	**942.1**

The following unaudited, pro forma results of operations are provided for the six months ended June 30, 2014, and the three and six months ended June 30, 2013. Pro forma results are not provided for the three months ended June 30, 2014, because the Permian Basin Acquisition occurred during the first quarter of 2014 and therefore there is no pro forma impact on the second quarter of 2014. These supplemental pro forma results of operations are provided for illustrative purposes only and may not be indicative of the actual results that would have been achieved by the acquired properties for the period presented or that may be achieved by such properties in the future. Future results may vary significantly from the results reflected in this pro forma financial information because of future events and transactions, as well as other factors. The pro forma information is based on QEP's consolidated results of operations for the three and six months ended June 30, 2014 and 2013, the acquired properties' historical results of operations, and estimates of the effect of the transaction on the combined results. The pro forma results of operations have been prepared by adjusting the historical results of QEP to include the historical results of the acquired properties based on information provided by the seller and the impact of the preliminary purchase price allocation. The pro forma results of operations do not include any cost savings or other synergies that may result from the Permian Basin Acquisition or any estimated costs that have been or will be incurred by the Company to integrate the acquired properties.

	Three Months Ended June 30,		Six Months Ended June 30,			
	2013	2013	2014	2014	2013	2013
	Actual	Pro forma	Actual	Pro forma	Actual	Pro forma
			(in millions, except per share data)			
Revenues	$ 751.0	$ 790.1	**$ 1,820.6**	**$ 1,846.7**	$ 1,447.5	$ 1,521.1
Net income (loss) attributable to QEP	178.4	182.6	**(52.6)**	**(45.6)**	174.1	186.2
Earnings per common share attributable to QEP						
Basic	$ 0.99	$ 1.02	**$ (0.29)**	**$ (0.25)**	$ 0.97	$ 1.04
Diluted	0.99	1.02	**(0.29)**	**(0.25)**	0.97	1.04

Divestitures

In June 2014, QEP Energy sold its interests in certain non-core properties in the Midcontinent area and other non-core assets in the Williston Basin for total cash proceeds of $702.3 million, subject to post-closing purchase price adjustments, and recorded a pre-tax loss of $200.9 million. An additional $28.7 million of consideration is currently being held in escrow related to unresolved title defects. During the quarter ended June 30, 2014, QEP Energy recorded the loss on its Condensed Consolidated Statement of Operations in "Net loss from asset sales".

Note 4 - QEP Midstream

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

Initial Public Offering

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

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

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

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

Note 5 – 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 equity-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents are considered participating securities and are included in the computation of earnings per share pursuant to the two-class method. The Company’s unvested restricted stock awards contain non-forfeitable dividend rights and participate equally with common stock with respect to dividends issued or declared. However, the Company’s unvested restricted stock does not have a contractual obligation to share in losses of the Company. The Company’s unexercised stock options do not contain rights to dividends. Under the two-class method, the earnings used to determine basic earnings per common share are reduced by an amount allocated to participating securities. When the Company records a net loss, none of the loss is allocated to the participating securities since the securities are not obligated to share in Company losses. Use of the two-class method has an insignificant impact on the calculation of basic and diluted earnings per common share. For the three and six months ended June 30, 2014, 0.4 million and 0.3 million shares, respectively, were not included in diluted common shares outstanding as they were anti-dilutive due to QEP's net loss. During the three and six months ended June 30, 2013, there were no anti-dilutive shares.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	**2014**	2013
	(in millions)			
Weighted-average basic common shares outstanding	**180.1**	179.3	**179.9**	179.1
Potential number of shares issuable upon exercise of in-the-money stock options under the Long-term Stock Incentive Plan	—	0.2	—	0.3
Average diluted common shares outstanding	**180.1**	179.5	**179.9**	179.4

Note 6 – 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 oil and gas wells, production facilities, midstream assets, and certain other properties. The fair values of such costs are estimated by Company personnel based on abandonment costs of similar assets and depreciated over the life of the related assets. Revisions to the ARO estimates result from changes in expected cash flows or material changes in estimated asset retirement costs. The ARO liability is adjusted to present value each period through an accretion calculation using a credit-adjusted risk-free interest rate. Of the $189.5 million and $193.6 million ARO liability for the periods ended June 30, 2014 and December 31, 2013, $1.0 million and $1.8 million was included, respectively, as a current liability in "Accounts payable and accrued expenses" on the Condensed Consolidated Balance Sheets.

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

	Asset Retirement Obligations
	2014
	(in millions)
ARO liability at January 1,	**$ 193.6**
Accretion	**4.4**
Additions[1]	**13.2**
Revisions	**(0.4)**
Liabilities settled[2]	**(21.3)**
ARO liability at June 30,	**$ 189.5**

[1] Additions include $9.7 million related to the Permian Basin Acquisition.
[2] Settlements include $20.0 million related to the property sales in the second quarter of 2014 (see Note 3 - Acquisitions and Divestitures).

Note 7 – 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. ASC 820 also establishes a fair-value hierarchy. Level 1 inputs are quoted prices (unadjusted) for identical assets or liabilities in active markets that the Company has the ability to access at the measurement date. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the asset or liability.

QEP has determined that its commodity derivative instruments are Level 2. The Level 2 fair value of commodity derivative contracts (see Note 8 - Derivative Contracts) is based on market prices posted on the respective commodity exchange on the last trading day of the reporting period and industry standard discounted cash flow models. QEP primarily applies the market approach for recurring fair value measurements and maximizes its use of observable inputs and minimizes its use of unobservable inputs. QEP considers bid and ask prices for valuing the majority of its assets and liabilities measured and reported at fair value. In addition to using market data, QEP makes assumptions in valuing its assets and liabilities, including assumptions about risk and the risks inherent in the inputs to the valuation technique. The Company's policy is to recognize significant transfers between levels at the end of the reporting period.

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

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

The fair value of financial assets and liabilities at June 30, 2014, is shown in the table below:

	Fair Value Measurements June 30, 2014				
	Gross Amounts of Assets and Liabilities				Net Amounts Presented on the Condensed Consolidated
	Level 1	Level 2	Level 3	Netting Adjustments[1]	Balance Sheets
	(in millions)				
Financial Assets					
Commodity derivative instruments - short-term	$ —	$ 4.3	$ —	$ (4.3)	$ —
Commodity derivative instruments - long-term	—	0.5	—	—	0.5
Interest rate swaps - long-term	—	1.2	—	—	1.2
Total financial assets	$ —	$ 6.0	$ —	$ (4.3)	$ 1.7
Financial Liabilities					
Commodity derivative instruments - short-term	$ —	$ 108.9	$ —	$ (4.3)	$ 104.6
Interest rate swaps - short-term	—	4.7	—	—	4.7
Commodity derivative instruments - long-term	—	16.1	—	—	16.1
Total financial liabilities	$ —	$ 129.7	$ —	$ (4.3)	$ 125.4

[1] The Company nets its derivative contract assets and liabilities outstanding with the same counterparty on the Condensed Consolidated Balance Sheets as the contracts contain netting provisions. Refer to Note 8 - Derivative Contracts, for additional information regarding the Company's derivative contracts.

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

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

[1] The Company nets its derivative contract assets and liabilities outstanding with the same counterparty on the Condensed Consolidated Balance Sheets as the contracts contain netting provisions. Refer to Note 8 - Derivative Contracts, for additional information regarding the Company's derivative contracts.

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

	Carrying Amount	**Level 1 Fair Value**	Carrying Amount	Level 1 Fair Value
	June 30, 2014		December 31, 2013	
	(in millions)			
Financial assets				
Cash and cash equivalents	**$ 702.3**	**$ 702.3**	$ 11.9	$ 11.9
Financial liabilities				
Checks outstanding in excess of cash balances	**$ 5.7**	**$ 5.7**	$ 90.9	$ 90.9
Long-term debt	**$ 3,910.8**	**$ 4,064.5**	$ 2,997.5	$ 3,034.9

The carrying amounts of cash and cash equivalents and checks outstanding in excess of cash balances approximate fair value. The fair value of fixed-rate long-term debt is based on the trading levels and dollar prices for the Company's debt at the end of the 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 ARO at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with property, plant and equipment. Significant Level 3 inputs used in the calculation of asset retirement obligations include plugging costs and remaining reserve lives. A reconciliation of the Company's ARO is presented in Note 6 – Asset Retirement Obligations.

Note 8 – Derivative Contracts

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

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

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

Effective January 1, 2012, QEP elected to de-designate all of its gas, oil and NGL derivative contracts that were previously designated as cash flow hedges and discontinue hedge accounting prospectively. As a result of discontinuing hedge accounting, the mark-to-market values at December 31, 2011, were fixed in Accumulated Other Comprehensive Income (AOCI) as of the de-designation date and are being reclassified into the Condensed Consolidated Statements of Operations as the transactions settle and affect earnings. As of December 31, 2013, all mark-to-market value was reclassified from AOCI. During the six months ended June 30, 2013, $40.7 million of unrealized gains, after tax, were reclassified from AOCI into the Condensed Consolidated Statements of Operations in "Realized and unrealized losses on derivative contracts" as the transactions settled. All realized and unrealized gains and losses from derivative instruments incurred after January 1, 2012, are presented in the Condensed Consolidated Statements of Operations in "Realized and unrealized losses on derivative contracts" below operating income.

QEP also uses interest rate swaps to mitigate a portion of its exposure to interest rate volatility risk associated with its $600.0 million term loan. For the $300.0 million term loan issued during 2012, QEP locked in a fixed interest rate of 1.07% in exchange for a variable interest rate indexed to the one-month LIBOR. For the incremental $300.0 million borrowed under the term loan during 2014, QEP locked in a fixed interest rate of 0.86%. The average effective interest rate on the $600.0 million term loan when combined with the fixed interest rate swaps for the six months ended June 30, 2014 was 2.96%. The interest rate swaps settle monthly and will mature in March 2017.

QEP Energy Derivative Contracts

The following table sets forth QEP Energy's quantities and average prices for its commodity derivative contracts as of June 30, 2014:

Year	Type of Contract	Index	Total Volumes	Average Swap price per unit
			(in millions)	
Gas sales			**(MMBtu)**	
2014	SWAP	NYMEX	14.7	$ 4.22
2014	SWAP	IFNPCR	40.5	$ 4.08
2015	SWAP	NYMEX	25.6	$ 4.14
2015	SWAP	IFNPCR	11.0	$ 4.06
Oil sales			**(Bbls)**	
2014	SWAP	NYMEX WTI	6.3	$ 93.54
2015	SWAP	NYMEX WTI	5.5	$ 89.14
2015	SWAP	BRENT ICE	0.4	$ 104.95

The following table sets forth QEP Energy's oil basis swaps as of June 30, 2014:

Year	Index	Index Less Differential	Total Volumes	Weighted Average Differential
			(in millions)	
Oil basis swaps			**(Bbls)**	
2014	NYMEX WTI	ICE Brent	0.4	$ 13.78
2014	NYMEX WTI	LLS	0.4	$ 4.03
2015	NYMEX WTI	LLS	0.1	$ 4.03

QEP Marketing Derivative Contracts

QEP Marketing enters into commodity derivative transactions to lock in a margin on gas volumes placed into storage and for marketing transactions in which QEP Marketing sells gas volumes at a fixed price. The following table sets forth QEP Marketing's volumes and swap prices for its commodity derivative contracts as of June 30, 2014:

Year	Type of Contract	Index	Total Volumes	Average Swap price per MMBtu
			(in millions)	
Gas sales			**(MMBtu)**	
2014	SWAP	IFNPCR	2.2	$ 3.89
Gas purchases			**(MMBtu)**	
2014	SWAP	IFNPCR	0.8	$ 3.82

QEP's Derivative Contracts

The following table sets forth QEP's notional amount and interest rate for its interest rate swaps outstanding as of June 30, 2014:

Notional amount	Type of Contract	Maturity	Fixed Rate Paid	Variable Rate Received
(in millions)				
$300.0	Swap	March 2017	1.07%	One-month LIBOR
$300.0	Swap	March 2017	0.86%	One-month LIBOR
$600.0			0.96%	

QEP Derivative Financial Statement Presentation

The following table identifies the condensed consolidated 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:

		Gross asset derivative instruments fair value		**Gross liability derivative instruments fair value**	
	Balance Sheet line item	**June 30, 2014**	December 31, 2013	**June 30, 2014**	December 31, 2013
		(in millions)		(in millions)	
Current:					
Commodity	Fair value of derivative contracts	**$ 4.3**	$ 5.5	**$ 108.9**	$ 29.4
Interest rate swaps	Fair value of derivative contracts	**—**	—	**4.7**	2.6
Long-term:					
Commodity	Fair value of derivative contracts	**0.5**	0.4	**16.1**	—
Interest rate swaps	Fair value of derivative contracts	**1.2**	0.6	**—**	—
Total derivative instruments		**$ 6.0**	$ 6.5	**$ 129.7**	$ 32.0

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

	Three Months Ended June 30,		Six Months Ended June 30,	
Derivative instruments not designated as cash flow hedges	**2014**	2013	**2014**	2013
Realized gains (losses) on commodity derivative contracts	(in millions)			
QEP Energy				
Gas derivative contracts	**$ (8.4)**	$ 24.9	**$ (28.8)**	$ 69.5
Oil derivative contracts	**(25.1)**	6.4	**(38.0)**	11.6
QEP Marketing				
Gas derivative contracts	**(0.6)**	(0.5)	**(2.0)**	1.0
Total realized gains (losses) on commodity derivative contracts	**(34.1)**	30.8	**(68.8)**	82.1
Unrealized gains (losses) on commodity derivative contracts				
QEP Energy				
Gas derivative contracts	**6.0**	61.3	**(18.1)**	(3.0)
Oil derivative contracts	**(57.8)**	16.8	**(78.9)**	(2.9)
QEP Marketing				
Gas derivative contracts	**0.7**	1.3	**0.4**	(0.4)
Total unrealized gains (losses) on commodity derivative contracts	**(51.1)**	79.4	**(96.6)**	(6.3)
Total realized and unrealized gains (losses) on commodity derivative contracts	**$ (85.2)**	$ 110.2	**$ (165.4)**	$ 75.8
Realized gains (losses) on interest rate swaps				
Realized losses on interest rate swaps	**$ (1.2)**	$ (0.7)	**$ (1.9)**	$ (1.3)
Unrealized gains (losses) on interest rate swaps				
Unrealized gains (losses) on interest rate swaps	**(1.6)**	4.5	**(1.6)**	4.9
Total realized and unrealized gains (losses) on interest rate swaps	**$ (2.8)**	$ 3.8	**$ (3.5)**	$ 3.6
Total net realized gains (losses) on derivative contracts	**$ (35.3)**	$ 30.1	**$ (70.7)**	$ 80.8
Total net unrealized gains (losses) on derivative contracts	**(52.7)**	83.9	**(98.2)**	(1.4)
Grand Total	**$ (88.0)**	$ 114.0	**$ (168.9)**	$ 79.4

Note 9 – Restructuring Costs

In December 2013, QEP announced its plan to pursue a separation of its midstream business, QEP Field Services. In connection with this announcement, the Board of Directors approved an employee retention plan to provide substantially all QEP Field Services' employees as of December 1, 2013, with a one-time lump-sum cash payment on the earlier of December 31, 2014, or whenever the separation of QEP Field Services occurs conditioned on continued employment with QEP Field Services or a successor through the payment date unless the employee is terminated prior to such date.

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

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

	Total Restructuring Costs					
		Recognized in Income				
	Total Expected to be Incurred	Period from Inception to June 30, 2014	Three Months Ended June 30,		Six Months Ended June 30, 2014	
			2014	2013	**2014**	2013
QEP Energy	(in millions)					
One-time termination benefits	$ 3.3	$ 3.3	**$ —**	$ 0.1	**$ —**	$ 0.3
Retention & relocation expense	3.7	3.7	**—**	0.1	**—**	0.2
Lease termination costs	0.6	0.6	**—**	—	**—**	—
Total restructuring costs	$ 7.6	$ 7.6	**$ —**	$ 0.2	**—**	0.5
QEP Field Services						
Retention & relocation expense	$ 10.5	$ 5.8	**$ 2.6**	$ —	**$ 4.8**	$ —
Total restructuring costs	$ 10.5	$ 5.8	**$ 2.6**	$ —	**$ 4.8**	$ —
QEP Marketing						
One-time termination benefits	$ 0.3	$ 0.3	**$ —**	$ —	**$ —**	$ 0.1
Total restructuring costs	$ 0.3	$ 0.3	**$ —**	$ —	**$ —**	$ 0.1
Total QEP						
One-time termination benefits	$ 3.6	$ 3.6	**$ —**	$ 0.1	**$ —**	$ 0.4
Retention & relocation expense	14.2	9.5	**2.6**	0.1	**4.8**	0.2
Lease termination costs	0.6	0.6	**—**	—	**—**	—
Total restructuring costs	$ 18.4	$ 13.7	**$ 2.6**	$ 0.2	**$ 4.8**	$ 0.6

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, 2013	$ —	$ 0.8	$ —	$ 0.8
Costs incurred and charged to expense	**—**	**4.8**	**—**	**4.8**
Costs paid or otherwise settled	**—**	**—**	**—**	**—**
Balance at June 30, 2014	**$ —**	**5.6**	**—**	**$ 5.6**

Note 10 – Debt

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

	June 30, 2014	December 31, 2013
	(in millions)	
QEP's revolving credit facility due 2016	**$ 1,093.0**	$ 480.0
QEP Midstream's revolving credit facility due 2018	**—**	—
Term loan due 2017	**600.0**	300.0
6.05% Senior Notes due 2016	**176.8**	176.8
6.80% Senior Notes due 2018	**134.0**	134.0
6.80% Senior Notes due 2020	**136.0**	136.0
6.875% Senior Notes due 2021	**625.0**	625.0
5.375% Senior Notes due 2022	**500.0**	500.0
5.25% Senior Notes due 2023	**650.0**	650.0
Total principal amount of debt	**3,914.8**	3,001.8
Less unamortized discount	**(4.0)**	(4.3)
Total long-term debt outstanding	**$ 3,910.8**	$ 2,997.5

Of the total debt outstanding on June 30, 2014, amounts outstanding under QEP's revolving credit facility due August 25, 2016, QEP Midstream's revolving credit facility due August 14, 2018, QEP's term loan due April 18, 2017, the 6.05% Senior Notes due September 1, 2016, and the 6.80% Senior Notes due April 1, 2018, will mature within the next five years.

Credit Facilities

QEP's Credit Facility

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

During the six months ended June 30, 2014 and 2013, QEP’s weighted-average interest rate on borrowings from its credit facility was 2.20% and 2.33%, respectively. At June 30, 2014 and December 31, 2013, QEP was in compliance with the covenants under the credit agreement. At June 30, 2014, there was $1,093.0 million outstanding and $3.8 million of letters of credit issued under the credit facility.

QEP Midstream's Credit Facility

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

As of June 30, 2014, and December 31, 2013, there have been no borrowings under QEP Midstream's credit facility and QEP Midstream was in compliance with the covenants under the QEP Midstream credit agreement.

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

Term Loan
QEP's $600.0 million unsecured term loan facility provides for borrowings at short-term interest rates and contains covenants, restrictions, and interest rates that are substantially the same as QEP's revolving credit facility. The term loan matures in April 2017, and the maturity date may be extended one year with the agreement of the lenders. In conjunction with the Permian Basin Acquisition, QEP borrowed an incremental $300.0 million available under the facility and increased total borrowings under the term loan to $600.0 million. There were no changes to the maturity date, pricing or covenants in the credit agreement. QEP incurred $1.1 million of debt issuance costs associated with the new term loan issuance.

During the six months ended June 30, 2014 and 2013, QEP's weighted-average interest rate on borrowings from the term loan was 2.23% for both periods. At June 30, 2014 and December 31, 2013, QEP was in compliance with the covenants under the term loan credit agreement.

Senior Notes
At June 30, 2014, the Company had $2,221.8 million principal amount of senior notes outstanding with maturities ranging from September 2016 to May 2023 and coupons ranging from 5.25% to 6.875%. The senior notes pay interest semi-annually, are unsecured senior obligations and rank equally with all of our other existing and future unsecured and senior obligations. QEP may redeem some or all of its senior notes at any time before their maturity at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption. The indentures governing QEP's senior notes contain customary events of default and covenants that may limit QEP's ability to, among other things, place liens on its property or assets.

Note 11 - Contingencies

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

Environmental Claims

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

In July 2010, QEP received a Notice of Potential Penalty (NOPP) from the Louisiana Department of Environmental Quality (LDEQ) regarding the assumption of ownership and operatorship of a single facility in Louisiana prior to transferring the facility's air quality permit. In 2011, QEP completed an internal audit, which identified 424 facilities in Louisiana for which QEP both failed to submit a complete permit application and to receive approval from the department prior to construction, modification, or operation. QEP has corrected and disclosed all instances of non-compliance to the LDEQ and is working with the department to resolve the NOPP. The LDEQ has assumed lead responsibility for enforcement of the NOPP, and may require the Company to pay a monetary penalty.

Litigation

Questar Gas Company v. QEP Field Services Company, Civil No. 120902969, Third Judicial District Court, State of Utah. QEP Field Services' former affiliate, Questar Gas Company (QGC), filed this complaint in state court in Utah on May 1, 2012, asserting claims for breach of contract, breach of implied covenant of good faith and fair dealing, and an accounting and declaratory judgment related to a 1993 gathering agreement (the 1993 Agreement) executed when the parties were affiliates. Specific monetary damages are not asserted. Under the 1993 Agreement, certain of QEP Field Services' systems provide gathering services to QGC charging an annual gathering rate which is based on the cost of service. QGC is disputing the annual calculation of the gathering rate. The annual gathering rate has been calculated in the same manner under the 1993 Agreement since it was amended in 1998, without any prior objection or challenge by QGC. At the closing of the Offering, the assets and agreement discussed above were assigned to QEP Midstream. QGC netted the disputed amount from its monthly payments of the gathering fees to QEP Field Services and has continued to net such amounts from its monthly payment to QEP Midstream. As of June 30, 2014, QEP Midstream has deferred revenue of $11.6 million related to the QGC disputed amount. QEP Field Services has filed counterclaims seeking damages and a declaratory judgment relating to its gathering services under the 1993 Agreement. QGC may seek to amend its complaint to add QEP Midstream as a defendant in the litigation. QEP Midstream has been indemnified by QEP for costs, expenses and other losses incurred by QEP Midstream in connection with the QGC dispute, subject to certain limitations, as set forth in the Omnibus Agreement entered into between QEP Midstream and QEP in connection with the IPO.

Rocky Mountain Resources, LLC v. QEP Energy Company, Wexpro Company, Ultra Resources, Inc. and Lance Oil & Gas Company, Inc., Civil No. 2011-7816, District Court of Sublette County, Wyoming. Rocky Mountain Resources, LLC (Rocky Mountain) filed its complaint on March 30, 2011, seeking determination of the existence of a 4% overriding royalty interest in State of Wyoming oil and gas Lease No. 79-0645 covering Section 16, T32-N R-109-W, Sublette County, Wyoming. QEP and the other defendants are current lessees of Lease 79-0645. Rocky Mountain alleges that the defendants have received benefits from Lease 79-0645 and have failed to pay Rocky Mountain monies associated with the claimed 4% overriding royalty interest since the issuance of the lease by the State of Wyoming in 1980. Rocky Mountain asserts claims for quiet title, declaratory judgment, breach of contract, breach of duty of good faith, conversion, constructive trust and prejudgment interest. On May 7, 2014, the trial court entered its order granting plaintiff's motion for summary judgment on the issue of whether the overriding royalty interest attaches to QEP's lease. On June 17, 2014, the Supreme Court of Wyoming denied QEP's Petition for Writ of Review. There are several affirmative defenses that remain to be tried and QEP continues to vigorously defend the case. A trial date is scheduled for February 2015. QEP estimates, based in part on damages asserted by the plaintiff, that the range of reasonably possible outcomes is no loss to a loss of approximately $20 million.

Gatti et al v. State of Louisiana et al, 589,350, 19th JDC, Parish of East Baton Rouge, Louisiana. In this putative class action arising out of the unitization practices and orders of the Louisiana Commissioner of Conservation (Commissioner), plaintiffs seek to represent a class of all Haynesville Shale mineral owners (alleged to be over 50,000 in number) against the Commissioner and all Haynesville Shale unit operators. Plaintiffs filed their complaint on April 8, 2010, and claim that the Commissioner exceeded his statutory authority in creating and perpetuating units larger than the area that can be efficiently and economically drained by a single well. They seek declaratory relief that would nullify all such improper orders, along with an unspecified amount of monetary damages from the unit operators sufficient to compensate the putative class members for the alleged dilution of their true interest in unit production as a result of "oversized" units and the "cloud on title" caused by having excessive and improperly sized units purport to hold their mineral leases via unit operations. All defendants filed exceptions to the plaintiffs' petition on the primary ground that plaintiffs had failed to comply with the exclusive statutory judicial review procedure (Louisiana Revised Statutes 30:12), which the trial court granted, dismissing the action in its entirety. On January 15, 2014, the Louisiana First Circuit Court of Appeal reversed and reinstated plaintiffs' claims. Defendants have asked for review of the Louisiana Supreme Court, which review is discretionary.

Yannick Gagné and others similarly situated v. QEP Resources, Inc., No. 480-06-1-132, Superior Court, Province of Quebec, Canada. Plaintiffs seek to represent a class of all persons who sustained damages as a result of the July 6, 2013 train derailment in Lac-Mégantic, Quebec, which resulted in substantial loss of life and property. The fourth amended motion to authorize the bringing of a class action was filed on February 19, 2014, and names numerous defendants. The plaintiffs contend that QEP, and other producer defendants, sold Bakken crude oil to third-party purchasers in North Dakota, who resold the oil and transported it on the derailed train. Plaintiffs alleged that QEP and the producer defendants, among other things, failed to ensure that the oil was adequately processed to remove volatile gases and vapors, knowingly added volatile light end petroleum liquids and/or vapors or blended the crude with condensate, failed to conduct adequate well site testing to determine the proper hazard classification of the oil, failed to properly classify the shipping requirements for the oil, failed to take reasonable care to ensure that the oil was properly labeled and shipped, failed to identify the risk of the train derailment and take action to prevent it, and failed to adopt, implement and enforce rules and procedures pertaining to the safe shipment of the oil. The plaintiffs seek damages, but specific monetary damages are not asserted. Class certification hearings are ongoing.

XTO Energy Inc. v. QEP Field Services Company, Civil No. 140900709, Third Judicial District Court, State of Utah. XTO Energy Inc. (XTO), filed this complaint in Utah state court on January 30, 2014, asserting claims for breach of contract, breach of implied covenant of good faith and fair dealing, unjust enrichment and an accounting related to a 2010 gas processing agreement (the Agreement). QEP Field Services processes XTO’s natural gas on a firm basis under the Agreement. The Agreement requires QEP Field Services to transport, fractionate and market XTO’s natural gas liquids derived from XTO’s processed gas. XTO is seeking monetary damages related to QEP Field Services allocation of charges related to XTO’s share of natural gas liquid transportation, fractionation and marketing costs associated with shortfalls in contractual firm processing volumes.

Note 12 – Equity-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 equity-based compensation is included in additional paid-in capital in the Condensed Consolidated Balance Sheets. There were 10.9 million shares available for future grants under the LTSIP at June 30, 2014. Equity-based compensation expense is recognized in “General and administrative” on the Condensed Consolidated Statements of Operations. During the three and six months ended June 30, 2014, QEP recognized $6.6 million and $13.4 million in total compensation expense related to equity-based compensation compared to $7.1 million and $13.2 million during the three and six months ended June 30, 2013.

QEP Midstream maintains a unit-based compensation plan for officers, directors and employees of the general partner of QEP Midstream and its affiliates and any consultants, affiliates of the general partner, or other individuals who perform services for QEP Midstream. The QEP Midstream 2013 Long-Term Incentive Plan (the QEP Midstream LTIP) permits various types of awards, including awards of restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights, profits interest units and other unit-based awards. Phantom unit awards granted during 2013 under the QEP Midstream LTIP will be settled with QEP Midstream units. During the three and six months ended June 30, 2014, QEP recognized $0.2 million and $0.6 million in compensation expense related to QEP Midstream LTIP.

Stock Options

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

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

	Stock Option Assumptions Six Months Ended June 30, 2014
Weighted-average grant-date fair value of awards granted during the period	**$ 10.11**
Weighted-average risk-free interest rate	**1.31%**
Weighted-average expected price volatility	**37.1%**
Expected dividend yield	**0.25%**
Expected term in years at the date of grant	**4.5**

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

	Options Outstanding	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
		(per share)	(in years)	(in millions)
Outstanding at December 31, 2013	1,794,187	$ 27.90		
Granted	282,236	31.67		
Exercised	(53,866)	22.57		
Forfeited	(14,842)	30.53		
Outstanding at June 30, 2014	**2,007,715**	**$ 28.55**	**2.27**	**$ 11.9**
Options Exercisable at June 30, 2014	**1,455,950**	**$ 27.65**	**2.79**	**$ 10.0**
Unvested Options at June 30, 2014	**551,765**	**$ 30.94**	**5.99**	**$ 1.9**

The total intrinsic value (the difference between the market price at the exercise date and the exercise price) of options exercised was $0.5 million and $4.2 million during the six months ended June 30, 2014 and 2013, respectively. As of June 30, 2014, $3.8 million of unrecognized compensation cost related to stock options granted under the LTSIP is expected to be recognized over a weighted-average period of 2.21 years. During the six months ended June 30, 2014, QEP received $1.2 million in cash in relation to the exercise of stock options during 2014.

Restricted Shares

Restricted share grants typically vest in equal installments over a three-year period from the grant date. The grant date fair value is determined based on the closing bid price of the Company's common stock on the grant date. The total fair value of restricted stock that vested during the six months ended June 30, 2014 and 2013, was $15.2 million and $15.0 million, respectively. The weighted average grant-date fair value of restricted stock was $31.63 per share and $30.10 per share for the six months ended June 30, 2014 and 2013, respectively. As of June 30, 2014, $29.7 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 2.33 years.

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

	Restricted Shares Outstanding	Weighted-Average Grant-Date Fair Value
		(per share)
Unvested balance at December 31, 2013	1,388,953	$ 30.96
Granted	886,783	31.63
Vested	(525,651)	31.89
Forfeited	(84,572)	30.93
Unvested balance at June 30, 2014	**1,665,513**	**$ 31.03**

Performance Share Units

The performance share units' cash payouts are dependent upon the Company’s total shareholder return compared to a group of its peers over a three-year period. The awards are denominated in share units but delivered in cash at the end of the performance period. The weighted average grant-date fair value of the performance share units was $31.67 per share and $30.12 per share for the six months ended June 30, 2014 and 2013, respectively. As of June 30, 2014, $11.1 million of unrecognized compensation cost, representing the fair market value of performance shares granted, is expected to be recognized over a weighted-average vesting period of 2.20 years.

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

	Performance Share Units Outstanding	Weighted-Average Grant-Date Fair Value
Unvested balance at December 31, 2013	480,660	$ 32.33
Granted	247,192	31.67
Vested and paid out	(55,659)	39.07
Vested and canceled [1]	(51,361)	39.07
Forfeited	(17,643)	30.35
Unvested balance at June 30, 2014	**603,189**	**$ 30.92**

(1) Represents units that vested but were not paid out. Payout of the performance share units are dependent upon the Company's total shareholder return compared to a group of its peers over a three-year period.

Note 13 – Employee Benefits

The Company maintains closed, defined-benefit pension and postretirement medical plans. QEP's pension plans include a qualified and a nonqualified retirement plan. The Company's postretirement medical plan is unfunded and provides certain health care and life insurance benefits for certain retired employees. During the six months ended June 30, 2014, the Company made contributions of $5.4 million to its funded qualified pension plan and $4.3 million to its unfunded nonqualified retirement plan. Contributions to funded qualified plans increase plan assets while contributions to unfunded nonqualified plans are used to fund current benefit payments. During the remainder of 2014, the Company expects to contribute approximately $2.7 million to its funded qualified pension plan, approximately $0.6 million to its unfunded nonqualified pension plans and approximately $0.1 million for retiree health care and life insurance benefits.

During the six months ended June 30, 2014, the Company recognized a $2.4 million loss on curtailment and $0.3 million expense for special termination benefits in connection with the second quarter 2014 property sales in the Midcontinent area (see Note 3 - Acquisitions and Divestitures). A curtailment is recognized immediately when there is a significant reduction in, or an elimination of, defined benefit accruals for present employees' future services. These expenses are included within "Net gain (loss) from asset sales" on the Condensed Consolidated Statements of Operations for the three and six months ended June 30, 2014.

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

	Pension			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	**2014**	2013
	(in millions)			
Service cost	**$ 0.7**	$ 0.9	**$ 1.4**	$ 1.9
Interest cost	**1.4**	1.3	**2.8**	2.5
Expected return on plan assets	**(1.2)**	(1.0)	**(2.4)**	(2.0)
Amortization of prior service costs [1]	**1.2**	1.3	**2.5**	2.5
Amortization of actuarial losses [1]	**0.2**	0.6	**0.4**	1.2
Curtailment cost	**2.0**	—	**2.0**	—
Special termination benefits	**0.3**	—	**0.3**	—
Periodic expense	**$ 4.6**	$ 3.1	**$ 7.0**	$ 6.1

(1) Amortization of prior service costs and actuarial losses out of AOCI are recognized in the Condensed Consolidated Statements of Operations in "General and administrative."

	Postretirement Benefits			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	**2014**	2013
	(in millions)			
Interest cost	**$ 0.1**	$ 0.1	**$ 0.2**	$ 0.2
Amortization of prior service costs [1]	**0.1**	0.1	**0.2**	0.2
Curtailment cost	**0.4**	—	**0.4**	—
Periodic expense	**$ 0.6**	$ 0.2	**$ 0.8**	$ 0.4

[1] Amortization of prior service costs out of AOCI are recognized in the Condensed Consolidated Statements of Operations in "General and administrative."

Note 14 – Operations by Line of Business

QEP's lines of business include oil and gas exploration and production (QEP Energy), midstream field services (QEP Field Services), which includes the ownership and operation of QEP Midstream, and marketing and corporate (QEP Marketing & Resources). The lines of business are managed separately and therefore the financial information is presented separately due to the distinct differences in the nature of operations of each line of business, among other factors. QEP Field Services owns a 57.8% ownership interest in QEP Midstream and it is consolidated under the voting interest model in QEP Field Services' operating results. The outside ownership interest in QEP Midstream is presented separately as a noncontrolling interest.

The following table is a summary of operating results for the three months ended June 30, 2014, by line of business:

	QEP Energy	QEP Field Services	QEP Marketing & Resources	Eliminations	QEP Consolidated
			(in millions)		
Revenues					
From unaffiliated customers	$ 687.2	$ 63.1	$ 186.4	$ —	$ 936.7
From affiliated customers	—	30.3	420.6	(450.9)	—
Total revenues	687.2	93.4	607.0	(450.9)	936.7
Operating expenses					
Purchased gas, oil and NGL expense	50.1	1.9	605.4	(421.7)	235.7
Lease operating expense	59.5	—	—	(2.0)	57.5
Gas, oil and NGL transportation and other handling costs	72.1	8.8	—	(26.6)	54.3
Gathering, processing and other	—	24.0	0.5	0.3	24.8
General and administrative	45.9	18.7	0.5	(0.9)	64.2
Production and property taxes	53.1	2.9	0.1	—	56.1
Depreciation, depletion and amortization	232.3	16.8	0.6	—	249.7
Other operating expenses	3.2	—	—	—	3.2
Total operating expenses	516.2	73.1	607.1	(450.9)	745.5
Net loss from asset sales	(200.8)	(0.2)	—		(201.0)
Operating income (loss)	(29.8)	20.1	(0.1)	—	(9.8)
Realized and unrealized losses on derivative contracts	(85.3)	—	(2.7)	—	(88.0)
Interest and other income	0.6	—	56.6	(56.4)	0.8
Income from unconsolidated affiliates	0.1	1.1	—	—	1.2
Interest expense	(56.6)	(0.7)	(44.8)	56.4	(45.7)
Income (loss) before income taxes	(171.0)	20.5	9.0	—	(141.5)
Income tax (provision) benefit	64.0	(7.1)	(2.7)	—	54.2
Net income (loss)	(107.0)	13.4	6.3	—	(87.3)
Net income attributable to noncontrolling interest	—	(5.0)	—	—	(5.0)
Net income (loss) attributable to QEP	$ (107.0)	$ 8.4	$ 6.3	$ —	$ (92.3)
Identifiable total assets	$ 9,481.7	$ 1,529.2	$ 564.1	$ (1,012.2)	$ 10,562.8

The following table is a summary of operating results for the three months ended June 30, 2013, by line of business:

	QEP Energy	QEP Field Services	QEP Marketing & Resources	Eliminations	QEP Consolidated
			(in millions)		
Revenues					
From unaffiliated customers	$ 528.5	$ 72.3	$ 150.2	$ —	$ 751.0
From affiliated customers	—	30.6	221.7	(252.3)	—
Total revenues	528.5	102.9	371.9	(252.3)	751.0
Operating expenses					
Purchased gas, oil and NGL expense	54.9	3.5	369.9	(221.3)	207.0
Lease operating expense	45.7	—	—	(2.2)	43.5
Gas, oil and NGL transportation and other handling costs	59.5	5.4	—	(27.6)	37.3
Gathering, processing and other	—	23.0	0.5	—	23.5
General and administrative	30.0	10.9	1.2	(1.2)	40.9
Production and property taxes	37.6	1.7	—	—	39.3
Depreciation, depletion and amortization	238.0	11.7	0.1	—	249.8
Other operating expenses	2.8	—	—	—	2.8
Total operating expenses	468.5	56.2	371.7	(252.3)	644.1
Net gain (loss) from assets sales	100.5	(0.1)	—	—	100.4
Operating income	160.5	46.6	0.2	—	207.3
Realized and unrealized gains on derivative contracts	109.4	—	4.6	—	114.0
Interest and other income	3.2	—	54.7	(54.8)	3.1
Income from unconsolidated affiliates	—	1.6	—	—	1.6
Interest expense	(48.9)	(5.3)	(42.0)	54.8	(41.4)
Income before income taxes	224.2	42.9	17.5	—	284.6
Income tax provision	(82.1)	(15.1)	(7.6)	—	(104.8)
Net income	142.1	27.8	9.9	—	179.8
Net income attributable to noncontrolling interest	—	(1.4)	—	—	(1.4)
Net income attributable to QEP	$ 142.1	$ 26.4	$ 9.9	$ —	$ 178.4
Identifiable total assets	$ 7,984.2	$ 1,704.4	$ 253.3	$ (494.8)	$ 9,447.1

The following table is a summary of operating results for the six months ended June 30, 2014, by line of business:

	QEP Energy	QEP Field Services	QEP Marketing & Resources	Eliminations	QEP Consolidated
			(in millions)		
Revenues					
From unaffiliated customers	$ 1,300.4	$ 142.9	$ 377.3	$ —	$ 1,820.6
From affiliated customers	—	56.7	732.7	(789.4)	—
Total revenues	1,300.4	199.6	1,110.0	(789.4)	1,820.6
Operating expenses					
Purchased gas, oil and NGL expense	88.1	1.9	1,103.3	(733.3)	460.0
Lease operating expense	115.9	—	—	(3.1)	112.8
Gas, oil and NGL transportation and other handling costs	136.6	12.4	—	(51.3)	97.7
Gathering, processing and other	—	49.7	0.9	—	50.6
General and administrative	87.7	33.1	1.7	(1.7)	120.8
Production and property taxes	100.5	4.7	0.2	—	105.4
Depreciation, depletion and amortization	455.7	33.3	0.9	—	489.9
Other operating expenses	7.4	—	—	—	7.4
Total operating expenses	991.9	135.1	1,107.0	(789.4)	1,444.6
Net loss from asset sales	(198.4)	(0.2)	—	—	(198.6)
Operating income	110.1	64.3	3.0	—	177.4
Realized and unrealized losses on derivative contracts	(163.8)	—	(5.1)	—	(168.9)
Interest and other income	3.5	—	105.4	(105.2)	3.7
Income from unconsolidated affiliates	0.1	3.3	—		3.4
Interest expense	(105.5)	(1.3)	(86.6)	105.2	(88.2)
Income (loss) before income taxes	(155.6)	66.3	16.7	—	(72.6)
Income tax (provision) benefit	58.1	(21.7)	(5.6)	—	30.8
Net income (loss)	(97.5)	44.6	11.1	—	(41.8)
Net income attributable to noncontrolling interest	—	(10.8)	—	—	(10.8)
Net income (loss) attributable to QEP	$ (97.5)	$ 33.8	$ 11.1	$ —	$ (52.6)
Identifiable total assets	$ 9,481.7	$ 1,529.2	$ 564.1	$ (1,012.2)	$ 10,562.8

The following table is a summary of operating results for the six months ended June 30, 2013, by line of business:

	QEP Energy	QEP Field Services	QEP Marketing & Resources	Eliminations	QEP Consolidated
			(in millions)		
Revenues					
From unaffiliated customers	$ 1,036.7	$ 136.7	$ 274.1	$ —	$ 1,447.5
From affiliated customers	—	58.2	438.9	(497.1)	—
Total revenues	1,036.7	194.9	713.0	(497.1)	1,447.5
Operating expenses					
Purchased gas, oil and NGL expense	120.6	8.6	712.4	(437.8)	403.8
Lease operating expense	86.7	—	—	(4.3)	82.4
Gas, oil and NGL transportation and other handling costs	115.7	8.2	—	(52.6)	71.3
Gathering, processing and other	—	43.3	0.8	—	44.1
General and administrative	66.7	20.4	2.2	(2.4)	86.9
Production and property taxes	72.3	2.8	0.1	—	75.2
Depreciation, depletion and amortization	476.1	27.5	0.4	—	504.0
Other operating expenses	7.9	—	—	—	7.9
Total operating expenses	946.0	110.8	715.9	(497.1)	1,275.6
Net gain (loss) from asset sales	100.6	(0.4)	—	—	100.2
Operating income (loss)	191.3	83.7	(2.9)	—	272.1
Realized and unrealized gains on derivative contracts	75.2	—	4.2	—	79.4
Interest and other income	4.9	0.3	105.9	(106.0)	5.1
Income from unconsolidated affiliates	—	2.9	—	—	2.9
Interest expense	(94.2)	(9.3)	(83.3)	106.0	(80.8)
Income before income taxes	177.2	77.6	23.9	—	278.7
Income tax provision	(64.9)	(27.6)	(10.1)	—	(102.6)
Net income	112.3	50.0	13.8	—	176.1
Net income attributable to noncontrolling interest	—	(2.0)	—	—	(2.0)
Net income attributable to QEP	$ 112.3	$ 48.0	$ 13.8	$ —	$ 174.1
Identifiable total assets	7,984.2	1,704.4	253.3	(494.8)	9,447.1

Note 15 - Subsequent Events

QEP Field Services Divestiture

On July 1, 2014, QEP Field Services sold 40% of the membership interests in Green River Processing, LLC (Green River Processing), a wholly owned subsidiary of QEP Field Services, to QEP Midstream for $230.0 million. QEP Midstream funded the Green River Processing Acquisition with $220.0 million of borrowings under their credit facility and cash on hand. The transaction will be accounted for as a transaction between entities under common control with the difference between the carrying amount and the purchase price recorded to equity.

Green River Processing owns the Blacks Fork processing complex and the Emigrant Trail processing plant, both of which are located in southwest Wyoming. The aggregate processing capacity of Green River Processing is up to 890 MMcf per day, comprised of up to 560 MMcf per day of cryogenic processing capacity and 330 MMcf per day of Joule-Thomson processing capacity. In addition, there is 15,000 bbl per day of NGL fractionation capacity at the Blacks Fork processing complex.

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

The following information updates the discussion of QEP's financial condition provided in its 2013 Annual Report on Form 10-K filing and analyzes the changes in the results of operations between the three and six months ended June 30, 2014 and 2013. For definitions of commonly used oil and gas terms found in this Quarterly Report on Form 10-Q, please refer to the "Glossary of Commonly Used Terms" provided in QEP's 2013 Annual Report on Form 10-K.

OVERVIEW

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

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

QEP's operations are focused in two geographic regions: the Northern Region (primarily in North Dakota, Wyoming and Utah) and the Southern Region (primarily in Texas, Louisiana, and Oklahoma) of the United States. QEP's corporate headquarters are located in Denver, Colorado. QEP owns and operates, directly or through its ownership in QEP Midstream, gathering, natural gas processing and treating facilities in the majority of its core producing areas outside of Oklahoma and Texas.

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

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

Strategies

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

- operate in a safe and environmentally responsible manner;
- allocate capital to those projects that generate the highest returns;
- acquire businesses and assets that complement or expand our current business;
- manage our asset portfolio by divesting of non-core assets;

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

Acquisitions

On February 25, 2014, QEP Energy acquired oil and gas properties in the Permian Basin of Texas for an aggregate purchase price of $942.1 million, subject to post-closing purchase price adjustments (the Permian Basin Acquisition). The acquired properties consist of approximately 26,500 net acres of producing and undeveloped oil and gas properties and approximately 270 vertical producing wells in the Permian Basin, which creates a new core area of operation for QEP Energy. The acquisition was funded with $50.0 million of restricted cash, $300.0 million from the Company's expanded term loan and the remainder was funded from its revolving credit facility.

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

Divestitures

The Company will periodically divest select non-core portfolio assets to redirect capital towards higher-return projects. In June 2014, QEP sold its interests in certain non-core properties in the Midcontinent area and other non-core assets in the Williston Basin for an aggregate sales price of approximately $702.3 million, subject to post-closing purchase price adjustments. The Company used the proceeds to repay borrowings on its revolving credit facility incurred to fund the Permian Basin Acquisition. The Company plans to offer additional non-core properties for sale in the second half of 2014. In 2013, QEP divested of certain non-core properties resulting in total cash proceeds of $205.8 million. For the remainder of 2014, the Company plans to focus future investment on QEP's operations in its core areas in the Williston, Permian, Pinedale, and Uinta basins.

In December 2013, QEP's Board of Directors authorized the Company to develop a plan to separate the business of QEP Field Services, including the Company's interest in QEP Midstream, from QEP. In June 2014, in conjunction with evaluating separation alternatives, QEP Field Services filed a Registration Statement on Form 10 with the U.S. Securities and Exchange Commission (SEC) in connection with the separation of QEP Field Services into a separate publicly traded company. The separation transaction is expected to close in the second half of 2014.

In May 2014, QEP Field Services entered into a purchase and sale agreement to sell 40% of the membership interests in Green River Processing LLC, a wholly owned subsidiary of QEP Field Services, to QEP Midstream for $230.0 million. The transaction closed on July 1, 2014.

Outlook

The Company has substantial acreage positions and operations in some of the most prolific hydrocarbon resource plays in the continental United States, including the Williston Basin, Permian Basin, Pinedale Anticline, Uinta Basin and Haynesville Shale. These resource plays are characterized by unconventional oil or gas accumulations in continuous tight sands or shales that underlie broad geographic areas. The lateral continuity of such resource plays means that aside from wells abandoned due to mechanical issues, the Company does not expect to drill many unsuccessful wells as it develops these resource plays. Resource plays allow the Company the opportunity to gain considerable operational efficiencies through high-density, repeatable drilling and completion operations. The Company has a large inventory of lower-risk, predictable development drilling locations across its acreage holdings in the onshore United States that provide a solid base for consistent growth in organic production and reserves. QEP believes that it has one of the lowest cash operating structures among its E&P company peers. However, in certain of its resource plays, QEP, along with its peers, has experienced increased drilling and completion costs which could impact near term drilling plans.

While historically a natural gas producer, the Company has increased its focus on growing the relative proportion of oil and NGL production in its E&P business. During the first half of 2014, which includes four months of results from the Permian Basin Acquisition, QEP Energy increased its oil and NGL production by 59% compared to the first half of 2013. Additionally, oil and NGL revenue represented 66% and 64% of QEP Energy's field-level revenue during the three and six months ended June 30, 2014, respectively, up from 54% and 55% during the three and six months ended June 30, 2013, respectively.

In January 2014 QEP's Board of Directors authorized the repurchase of up to $500.0 million of the Company's outstanding shares of common stock. This authorization is effective until January 2015. The timing and amount of any QEP share repurchases will depend upon a number of factors, including general market conditions, the Company’s financial position and the estimated intrinsic value of the Company’s shares. The repurchase authorization does not obligate QEP to acquire any specific number or value of shares, may be discontinued at any time and is governed by the Company's various restrictions on trading activity. During the three and six months ended June 30, 2014, no shares were repurchased.

Financial and Operating Results

QEP Energy reported total equivalent production of 83.9 Bcfe during the second quarter of 2014 and 157.6 Bcfe in the first half of 2014, an increase of 8% and 1%, respectively, compared to the same periods in 2013. Oil and NGL production increased to 5,866.6 Mbbls and to 10,746.9 Mbbls in the three and six months ended June 30, 2014, increases of 68% and 59%, respectively, from the comparable periods in 2013. These increases were partially offset by a decrease in gas production to 48.6 Bcf in the second quarter of 2014 and to 93.1 Bcf in the first half of 2014, decreases of 15% and 19%, respectively, from the comparable periods of 2013. The Company's 2012 Williston Basin acquisition contributed oil and NGL production of 1,849 Mbbls and 3,431 Mbbls in the three and six months ended June 30, 2014, respectively. Additionally, QEP Energy completed the Permian Basin Acquisition on February 25, 2014, which contributed 721.6 Mbbls of oil and NGL production, $61.9 million of revenue and $14.0 million of net income during the period from February 25, 2014 to June 30, 2014. QEP Energy benefited from higher average realized prices (including the impact of settled commodity derivatives) which increased 12% to $7.22 per Mcfe during the second quarter of 2014 and 14% to $7.28 per Mcfe during the six months ended June 30, 2014 compared to the comparable periods in 2013.

During the second quarter of 2014, QEP Field Services' NGL sales volumes decreased 31%, fee-based processing volumes decreased 4% and gathering throughput volumes decreased 8% as compared to the second quarter of 2013. QEP Field Services experienced an increase in the average net realized NGL sales price of 38%, and an increase in natural gas gathering rates of 3% during the second quarter of 2014. There was no change in fee-based processing rate during the second quarter of 2014 compared to 2013. During the first half of 2014, QEP Field Services' NGL sales volumes increased 4%, fee-based processing volumes decreased 2% and gathering throughput volumes decreased 10% as compared to the first half of 2013. QEP Field Services experienced an increase in the average net realized NGL sales price of 35% during the first half of 2014. There was no change in natural gas gathering rates or fee-based processing rate during the first half of 2014.

Factors Affecting Results of Operations

Oil, Gas, and NGL Prices
Historically, field-level prices received for QEP's gas, oil and NGL production have been volatile and unpredictable, and that volatility is expected to continue. In recent years, domestic natural gas supply has grown faster than natural gas demand, driven by advances in drilling and completion technologies, including horizontal drilling and multi-stage hydraulic fracturing. These changes have allowed producers to extract increased quantities of natural gas from shale, tight sand formations, and other unconventional reservoirs. Increased natural gas supplies have resulted in downward pressure on natural gas prices, while concern about the global economy and other factors has created volatility in the price of oil. Additionally, QEP's NGL prices are affected by ethane recovery. When ethane is recovered as an NGL instead of being sold as part of the natural gas stream, the average NGL barrel sales price decreases as the ethane price is lower than the remaining NGL components. Changes in the market prices for gas, oil, and NGL directly impact many aspects of QEP's business, including its financial condition, revenues, results of operations, planned drilling activity and related capital expenditures, liquidity, rate of growth, and costs of goods and services required to drill and complete wells, and may impact the carrying value of its oil and 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. At June 30, 2014, assuming forecasted 2014 annual production of 297 Bcfe, QEP Energy had approximately 60% of its forecasted gas equivalent production covered with fixed-price swaps, including 61% of its forecasted gas production and 81% of its forecasted oil production covered with fixed-price swaps. See Part 1, Item 3 “Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk Management” for further details concerning QEP’s commodity derivatives transactions. In addition, as a result of the continued spread between oil and gas prices, QEP Energy has allocated approximately 96% of its forecasted 2014 drilling and completion capital expenditure budget to oil and liquids-rich gas projects in its portfolio.

Global Geopolitical and Macroeconomic Factors
QEP continues to monitor the outlook of the global economy, including political unrest in Eastern Europe, the Middle East, and Africa; a slowing of growth in Asia; the United States federal budget deficit; the potential for future shut-downs of federal government offices including the Department of Interior (including the Bureau of Land Management (BLM) and Bureau of Indian Affairs (BIA), which process permits to drill and rights-of-way for construction of gathering lines and other midstream infrastructure on federal (BLM) and Native American (BIA and BLM) minerals and surface); changes in regulatory oversight policy; commodity price volatility; and other factors. A dramatic decline in regional or global economic conditions, a major recession or depression, regional political instability, economic sanctions, war, or other factors beyond the control of QEP could have a significant impact on gas, oil and NGL supply, demand and prices, the Company's ability to continue its planned drilling programs on federal and Native American lands, and could materially impact the Company's financial position, results of operations and cash flow from operations.

Supply, Demand and Other Market Risk Factors
Since 2008, U.S. natural gas directed drilling rig count has decreased as producers reduced drilling activity for dry natural gas in response to lower natural gas prices and directed investment toward oil and liquid-rich projects. A reduction in natural gas production has lagged the downturn in the natural gas rig count because efficiency gains have allowed more wells to be drilled and completed per operating rig, higher per-well natural gas production from horizontal wells and increased amounts of natural gas produced in association with crude oil. As a result, U.S. natural gas production continued to increase throughout 2013 and the first half of 2014 despite the decreased rig-count. However, strong natural gas demand from electric power generation, cold winter weather during the 2013-2014 heating season, and other demand sources have caused a general firming of natural gas prices during the last half of 2013 and into 2014. Despite recent increases in natural gas prices, QEP expects U.S. natural gas prices to remain range-bound over the near term. Relatively low natural gas prices have caused U.S. E&P companies, including QEP, to shift capital investments away from predominantly dry gas areas toward plays that are known to have liquids-rich oil and gas. This shift in focus has caused domestic NGL production to increase dramatically. Increased NGL production and price dislocations from infrastructure bottlenecks in certain regions have all contributed to a weakening of domestic NGL prices, particularly ethane. QEP expects that ethane prices will continue to be range-bound until new ethylene crackers are built; however, the prices of heavier components of the NGL barrel have strengthened as a result of recent weather conditions combined with newly commissioned export facilities. QEP anticipates global oil prices will remain near current levels, assuming the global economy and socio-political backdrops remain relatively stable. Disruption to the global oil supply system, political and/or economic instability, and/or other factors could trigger additional volatility in oil prices. In addition, transportation, refining, or other infrastructure constraints could introduce significant price differentials between regional markets where QEP sells its oil production and national (NYMEX or Cushing) and global (Brent or U.S. Gulf Coast) markets.

Because of the global and regional price volatility and the uncertainty around the natural gas, oil and NGL price environments, QEP continues to manage its capital spending program and liquidity accordingly.

Potential for Future Asset Impairments

The carrying value of the Company's properties is sensitive to declines in gas, oil and NGL prices. These assets are at risk of impairment if future prices for gas, oil or NGL prices decline and/or drilling and completion costs increase. The cash flow model that the Company uses to assess proved properties for impairment includes numerous assumptions, such as management's estimates of future oil, gas and NGL production, market outlook on forward commodity prices, operating and development costs, and discount rates. All inputs to the cash flow model must be evaluated at each date of estimate. However, a decrease in forward gas, oil or NGL prices alone could result in an impairment of properties. The Company recorded $3.5 million in impairments of unproved properties and no impairment of proved properties during the first half of 2014.

Multi-Well Pad Drilling

To reduce the costs of well location construction and rig mobilization and demobilization and to obtain other efficiencies, QEP utilizes multi-well pad drilling where practical. Because wells drilled on a pad are not brought into production until all wells on the pad are drilled and completed and the drilling rig is moved from the location, multi-well pad drilling delays the commencement of production, which may cause volatility in QEP’s quarterly operating results.

Critical Accounting Estimates

QEP’s significant accounting policies are described in Item 7 of Part II of its 2013 Annual Report on Form 10-K. The Company’s condensed consolidated financial statements are prepared in accordance with GAAP. The preparation of the Company’s condensed consolidated financial statements requires management to make assumptions and estimates that affect the reported results of operations and financial position. QEP’s accounting policies on oil and gas reserves, successful efforts accounting for oil and gas operations, impairment of oil and gas properties, asset retirement obligations, accounting for derivative contracts, revenue recognition, environmental obligations, litigation and other contingencies, benefit plan obligations, equity-based compensation, income taxes, and purchase price allocations, among others, may involve a high degree of complexity and judgment on the part of management.

RESULTS OF OPERATIONS

Net Income (Loss)

QEP incurred a net loss during the second quarter of 2014 of $92.3 million, or $0.51 per diluted share, compared to net income of $178.4 million, or $0.99 per diluted share, in the second quarter of 2013. The decrease in the second quarter of 2014 was due to a $249.1 million decrease in QEP Energy’s net income, an $18.0 million decrease in QEP Field Services' net income and a $3.6 million decrease in QEP Marketing and Resources' net income. QEP Energy's net income decrease was primarily the result of a loss on sale of $200.9 million related to the disposal of non-core properties in the Midcontinent area and other non-core assets in the Williston Basin, unrealized losses on derivative instruments in the second quarter of 2014 compared to gains in the comparable 2013 period, higher operating expenses and lower oil and NGL realized prices and gas production when compared to the second quarter of 2013. These decreases were partially offset by increased oil and NGL production in the second quarter of 2014 compared to the second quarter of 2013. The decrease in QEP Field Services’ net income during the second quarter of 2014 was driven by a $5.3 million decrease in the keep-whole processing margin, a $7.2 million decrease in gathering margin and a $3.6 million increase net income attributable to noncontrolling interest due to QEP Midstream's formation and IPO in the third quarter of 2013. QEP Marketing and Resources' net income decreased in the second quarter of 2014 primarily due to realized and unrealized losses on derivative instruments compared to gains in the second quarter of 2013.

QEP incurred a net loss during the first half of 2014 of $52.6 million, or $0.29 per diluted share, compared to a net income of $174.1 million, or $0.97 per diluted share in the first half of 2013. The decrease in the first half of 2014 is due to a $209.8 million decrease in QEP Energy's net income, a $14.2 million decrease in QEP Field Services' net income and a $2.7 million decrease in QEP Marketing and Resources' net income. QEP Energy's net income decreased because of the loss on the disposal of the non-core properties of $200.9 million, unrealized losses on derivative instruments in the first half of 2014 compared to gains in the first half of 2013, and higher operating expenses partially offset by higher oil and NGL production. QEP Field Services' net income decreased in the first half of 2014 compared to 2013 due to a $11.0 million decreases in the gathering margin, an $8.8 million increase in net income attributable to noncontrolling interest due to the formation and IPO of QEP Midstream in the third quarter of 2013 and higher other operating expenses, partially offset by a $11.6 million increase in the processing margin. QEP Marketing and Resources' net income decreased in the first half of 2014 primarily due to realized and unrealized losses on derivative instruments compared to a gain in the first half of 2013.

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Change	**2014**	2013	Change
			(in millions)			
QEP Energy	**$ (107.0)**	$ 142.1	$ (249.1)	**$ (97.5)**	$ 112.3	$ (209.8)
QEP Field Services	**8.4**	26.4	(18.0)	**33.8**	48.0	(14.2)
QEP Marketing & Resources	**6.3**	9.9	(3.6)	**11.1**	13.8	(2.7)
Net income (loss) attributable to QEP	**$ (92.3)**	$ 178.4	$ (270.7)	**$ (52.6)**	$ 174.1	$ (226.7)
Earnings (loss) per diluted share	**$ (0.51)**	$ 0.99	$ (1.50)	**$ (0.29)**	$ 0.97	$ (1.26)
Average diluted shares	**180.1**	179.5	0.6	**179.9**	179.4	0.5

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 oil and gas producing companies. Management defines Adjusted EBITDA as earnings before interest, income taxes, depreciation, depletion and amortization (EBITDA) adjusted to exclude changes in fair value of derivative contracts, exploration expenses, gains and losses from asset sales, impairment, and certain other non-cash and/or non-recurring items.

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Change	**2014**	2013	Change
			(in millions)			
QEP Energy	**$ 373.1**	$ 332.1	$ 41.0	**$ 704.9**	$ 655.8	$ 49.1
QEP Field Services	**29.0**	58.3	(29.3)	**82.2**	111.5	(29.3)
QEP Marketing & Resources	**(1.3)**	(0.9)	(0.4)	**—**	(2.8)	2.8
Adjusted EBITDA	**$ 400.8**	$ 389.5	$ 11.3	**$ 787.1**	$ 764.5	$ 22.6

Adjusted EBITDA increased to $400.8 million in the second quarter of 2014 from $389.5 million in the second quarter of 2013, due to a 67% increase in oil production and a 69% increase in NGL production, partially offset by a 15% decrease in gas production and decreases of 7% and 17%, respectively, in average net realized equivalent oil and NGL prices.

Adjusted EBITDA increased to $787.1 million in the first half of 2014 from $764.5 million in the first half of 2013, due to a 61% increase in oil production and a 55% increase in NGL production, partially offset by a 19% decrease in gas production and decreases of 9% and 15%, respectively, in average net realized equivalent oil and NGL prices.

The following tables are reconciliations of Adjusted EBITDA to net income (loss) attributable to QEP, the most comparable GAAP financial measure:

	QEP Energy	**QEP Field Services**	**QEP Marketing & Resources**	**QEP**
Three Months Ended June 30, 2014		(in millions)		
Net income (loss) income attributable to QEP	**$ (107.0)**	**$ 8.4**	**$ 6.3**	**$ (92.3)**
Unrealized losses on derivative contracts	**51.8**	**—**	**0.9**	**52.7**
Net loss from asset sales	**200.8**	**0.2**	**—**	**201.0**
Interest and other income	**(0.6)**	**—**	**(0.2)**	**(0.8)**
Income tax (benefit) provision	**(64.0)**	**7.1**	**2.7**	**(54.2)**
Interest expense (income)[1]	**56.6**	**0.5**	**(11.6)**	**45.5**

	QEP Energy	QEP Field Services	QEP Marketing & Resources	QEP
Depreciation, depletion and amortization[2]	**232.3**	**12.8**	**0.6**	**245.7**
Impairment	**1.5**	**—**	**—**	**1.5**
Exploration expenses	**1.7**	**—**	**—**	**1.7**
Adjusted EBITDA	**$ 373.1**	**$ 29.0**	**$ (1.3)**	**$ 400.8**
Three Months Ended June 30, 2013				
Net income attributable to QEP	$ 142.1	$ 26.4	$ 9.9	$ 178.4
Unrealized gains on derivative contracts	(78.1)	—	(5.8)	(83.9)
Net (gain) loss from asset sales	(100.5)	0.1	—	(100.4)
Interest and other (income) loss	(3.2)	—	0.1	(3.1)
Income tax provision	82.1	15.1	7.6	104.8
Interest expense (income)	48.9	5.3	(12.8)	41.4
Depreciation, depletion and amortization[2]	238.0	11.4	0.1	249.5
Impairment	0.2	—	—	0.2
Exploration expenses	2.6	—	—	2.6
Adjusted EBITDA	$ 332.1	$ 58.3	$ (0.9)	$ 389.5
Six Months Ended June 30, 2014				
Net income (loss) income attributable to QEP	**$ (97.5)**	**$ 33.8**	**$ 11.1**	**$ (52.6)**
Unrealized losses on derivative contracts	**97.0**	**—**	**1.2**	**98.2**
Net loss from asset sales	**198.4**	**0.2**	**—**	**198.6**
Interest and other income	**(3.5)**	**—**	**(0.2)**	**(3.7)**
Income tax (benefit) provision	**(58.1)**	**21.7**	**5.6**	**(30.8)**
Interest expense (income) [1]	**105.5**	**0.9**	**(18.6)**	**87.8**
Depreciation, depletion and amortization[2]	**455.7**	**25.6**	**0.9**	**482.2**
Impairment	**3.5**	**—**	**—**	**3.5**
Exploration expenses	**3.9**	**—**	**—**	**3.9**
Adjusted EBITDA	**$ 704.9**	**$ 82.2**	**$ —**	**$ 787.1**
Six Months Ended June 30, 2013				
Net income attributable to QEP	$ 112.3	$ 48.0	$ 13.8	$ 174.1
Unrealized (gains) losses on derivative contracts	5.9	—	(4.5)	1.4
Net (gain) loss from asset sales	(100.6)	0.4	—	(100.2)
Interest and other (income) expense	(4.9)	(0.3)	0.1	(5.1)
Income tax provision	64.9	27.6	10.1	102.6
Interest expense (income)	94.2	9.3	(22.7)	80.8
Depreciation, depletion and amortization[2]	476.1	26.5	0.4	503.0
Impairment	0.2	—	—	0.2
Exploration expenses	7.7	—	—	7.7
Adjusted EBITDA	$ 655.8	$ 111.5	$ (2.8)	$ 764.5

[1] Excludes noncontrolling interest's share of $0.2 million and $0.4 million during the three and six months ended June 30, 2014, respectively, of interest expense attributable to QEP Midstream.

(2) Excludes noncontrolling interest's share of $4.0 million and $0.3 million during the three months ended June 30, 2014 and 2013, respectively, and $7.7 million and $1.4 million during the six months ended June 30, 2014 and 2013, respectively, of depreciation, depletion and amortization attributable to Rendezvous Gas Services, L.L.C and QEP Midstream.

QEP ENERGY

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Change	**2014**	2013	Change
Revenues			(in millions)			
Gas sales	**$ 215.1**	$ 218.1	$ (3.0)	**$ 437.6**	$ 415.7	$ 21.9
Oil sales	**358.5**	208.3	150.2	**647.2**	402.5	244.7
NGL sales	**64.8**	46.1	18.7	**127.9**	96.7	31.2
Purchased gas, oil and NGL sales	**49.8**	54.5	(4.7)	**86.9**	117.3	(30.4)
Other	**(1.0)**	1.5	(2.5)	**0.8**	4.5	(3.7)
Total revenues	**687.2**	528.5	158.7	**1,300.4**	1,036.7	263.7
Operating expenses						
Purchased gas, oil and NGL expense	**50.1**	54.9	(4.8)	**88.1**	120.6	(32.5)
Lease operating expense	**59.5**	45.7	13.8	**115.9**	86.7	29.2
Gas, oil and NGL transportation and other handling costs	**72.1**	59.5	12.6	**136.6**	115.7	20.9
General and administrative	**45.9**	30.0	15.9	**87.7**	66.7	21.0
Production and property taxes	**53.1**	37.6	15.5	**100.5**	72.3	28.2
Depreciation, depletion and amortization	**232.3**	238.0	(5.7)	**455.7**	476.1	(20.4)
Exploration expenses	**1.7**	2.6	(0.9)	**3.9**	7.7	(3.8)
Impairment	**1.5**	0.2	1.3	**3.5**	0.2	3.3
Total operating expenses	**516.2**	468.5	47.7	**991.9**	946.0	45.9
Net gain (loss) from asset sales	**(200.8)**	100.5	(301.3)	**(198.4)**	100.6	(299.0)
Operating income (loss)	**(29.8)**	160.5	(190.3)	**110.1**	191.3	(81.2)
Realized gains (losses) on derivative instruments	**(33.5)**	31.3	(64.8)	**(66.8)**	81.1	(147.9)
Unrealized gains (losses) on derivative instruments	**(51.8)**	78.1	(129.9)	**(97.0)**	(5.9)	(91.1)
Interest and other income	**0.6**	3.2	(2.6)	**3.5**	4.9	(1.4)
Income from unconsolidated affiliates	**0.1**	—	0.1	**0.1**	—	0.1
Interest expense	**(56.6)**	(48.9)	(7.7)	**(105.5)**	(94.2)	(11.3)
Income (loss) before income taxes	**(171.0)**	224.2	(395.2)	**(155.6)**	177.2	(332.8)
Income tax (provision) benefit	**64.0**	(82.1)	146.1	**58.1**	(64.9)	123.0
Net income (loss) attributable to QEP Energy	**$ (107.0)**	$ 142.1	$ (249.1)	**$ (97.5)**	$ 112.3	$ (209.8)
Production volumes (Bcfe)						
Northern Region						
Pinedale	**25.3**	23.2	2.1	**46.2**	44.9	1.3
Williston Basin	**19.4**	11.1	8.3	**36.2**	20.1	16.1
Uinta Basin	**6.8**	7.0	(0.2)	**13.0**	12.8	0.2
Other Northern	**3.5**	3.5	—	**6.0**	7.0	(1.0)
Southern Region						
Haynesville/Cotton Valley	**13.1**	18.8	(5.7)	**27.5**	41.1	(13.6)
Permian Basin	**4.2**	—	4.2	**5.4**	—	5.4
Midcontinent	**11.6**	14.3	(2.7)	**23.3**	30.0	(6.7)
Total production	**83.9**	77.9	6.0	**157.6**	155.9	1.7
Total equivalent prices (per Mcfe)						
Average equivalent field-level price	**$ 7.62**	$ 6.07	$ 1.55	**$ 7.70**	$ 5.87	$ 1.83
Commodity derivative impact	**(0.40)**	0.40	(0.80)	**(0.42)**	0.52	(0.94)
Net realized equivalent price	**$ 7.22**	$ 6.47	$ 0.75	**$ 7.28**	$ 6.39	$ 0.89

Revenue, Volume and Price Variance Analysis

The following table shows volume and price related changes for each of QEP Energy's major revenue categories for the three and six months ended June 30, 2014, compared to the three and six months ended June 30, 2013:

	Gas	Oil	NGL	Total
	(in millions)			
QEP Energy Production Revenues				
Three months ended June 30, 2013 Revenues	$ 218.1	$ 208.3	$ 46.1	$ 472.5
Changes associated with volumes [1]	(31.8)	139.3	31.9	139.4
Changes associated with prices [2]	28.8	10.9	(13.2)	26.5
Three months ended June 30, 2014 Revenues	**$ 215.1**	**$ 358.5**	**$ 64.8**	**$ 638.4**
QEP Energy Production Revenues				
Six Months ended June 30, 2013 Revenues	415.7	402.5	96.7	$ 914.9
Changes associated with volumes [1]	(80.4)	246.4	53.5	219.5
Changes associated with prices [2]	102.3	(1.7)	(22.3)	78.3
Six Months ended June 30, 2014 Revenues	**$ 437.6**	**$ 647.2**	**$ 127.9**	**$ 1,212.7**

(1) The revenue variance attributed to the change in volume is calculated by multiplying the change in volumes from the three and six months ended June 30, 2014, as compared to the three and six months ended June 30, 2013, by the average field-level price for the three and six months ended June 30, 2013.

(2) The revenue variance attributed to the change in price is calculated by multiplying the change in average field-level prices from the three and six months ended June 30, 2014, as compared to the three and six months ended June 30, 2013, by volumes for the three and six months ended June 30, 2014.

Gas Volumes and Prices

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Change	**2014**	2013	Change
Gas production volumes (Bcf)						
Northern Region						
Pinedale	**19.1**	20.1	(1.0)	**35.0**	39.1	(4.1)
Williston Basin	**1.2**	0.8	0.4	**1.9**	1.5	0.4
Uinta Basin	**4.3**	4.9	(0.6)	**8.4**	9.0	(0.6)
Other Northern	**2.9**	3.2	(0.3)	**5.1**	6.0	(0.9)
Southern Region						
Haynesville/Cotton Valley	**13.0**	18.7	(5.7)	**27.3**	40.9	(13.6)
Permian Basin	**0.9**	—	0.9	**1.1**	—	1.1
Midcontinent	**7.2**	9.2	(2.0)	**14.3**	18.9	(4.6)
Total production	**48.6**	56.9	(8.3)	**93.1**	115.4	(22.3)
Gas prices (per Mcf)						
Northern Region	**$ 4.44**	$ 3.90	$ 0.54	**$ 4.75**	$ 3.65	$ 1.10
Southern Region	**4.40**	3.76	0.64	**4.65**	3.56	1.09
Average field-level price	**$ 4.42**	$ 3.83	$ 0.59	**$ 4.70**	$ 3.60	$ 1.10
Commodity derivative impact	**(0.17)**	0.44	(0.61)	**(0.31)**	0.61	(0.92)
Net realized price	**$ 4.25**	$ 4.27	$ (0.02)	**$ 4.39**	$ 4.21	$ 0.18

Gas revenues decreased $3.0 million, or 1%, in the second quarter of 2014 when compared to the second quarter of 2013, due to lower gas production partially offset by higher field-level prices. The decrease in production volumes was primarily driven by the continued suspension of QEP's Haynesville/Cotton Valley operated drilling program. Production also decreased for the Midcontinent properties as a result of fewer net well completions throughout the second half of 2013 and the first half of 2014 compared to the prior year period and divestitures of non-core properties in the Midcontinent in the third quarter of 2013.

Additionally, gas production decreased in QEP's Pinedale field due to completions of wells in late 2013 in which QEP had no working interest and ethane recovery in the second quarter of 2014, in which ethane is extracted from the gas stream and sold as an NGL, compared to ethane rejection in 2013, in which ethane is sold in the gas stream.

Gas revenues increased $21.9 million, or 5%, in the first half of 2014 when compared to the first half of 2013, due to higher field-level prices partially offset by lower volumes. The decrease in production volumes was primarily driven by the continued suspension of QEP's Haynesville/Cotton Valley operated drilling program. Production also decreased for the Midcontinent properties as a result of fewer net well completions throughout the second half of 2013 and the first half of 2014 compared to the prior year period and divestitures of non-core properties in the Midcontinent in the third quarter of 2013. Additionally, production decreased in QEP's Pinedale field due to partial ethane recovery in the first half of 2014, compared to ethane rejection in 2013, as well as completions of wells in late 2013 in which QEP had no working interest.

Oil Volumes and Prices

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Change	**2014**	2013	Change
Oil production volumes (Mbbl)						
Northern Region						
Pinedale	**159.7**	161.1	(1.4)	**292.8**	309.9	(17.1)
Williston Basin	**2,831.5**	1,573.8	1,257.7	**5,351.7**	2,842.8	2,508.9
Uinta Basin	**229.9**	235.3	(5.4)	**442.3**	451.6	(9.3)
Other Northern	**92.0**	67.7	24.3	**141.1**	152.0	(10.9)
Southern Region						
Haynesville/Cotton Valley	**11.4**	10.8	0.6	**20.6**	22.4	(1.8)
Permian Basin	**418.2**	—	418.2	**558.2**	—	558.2
Midcontinent	**237.9**	336.5	(98.6)	**485.9**	745.4	(259.5)
Total production	**3,980.6**	2,385.2	1,595.4	**7,292.6**	4,524.1	2,768.5
Oil prices (per bbl)						
Northern Region	**$ 88.93**	$ 86.98	$ 1.95	**$ 87.81**	$ 89.05	$ (1.24)
Southern Region	**95.68**	89.27	6.41	**94.23**	88.57	5.66
Average field-level price	**$ 90.06**	$ 87.31	$ 2.75	**$ 88.74**	$ 88.97	$ (0.23)
Commodity derivative impact	**(6.29)**	2.68	(8.97)	**(5.21)**	2.55	(7.76)
Net realized price	**$ 83.77**	$ 89.99	$ (6.22)	**$ 83.53**	$ 91.52	$ (7.99)

Oil revenues increased $150.2 million, or 72%, in the second quarter of 2014 when compared to the second quarter of 2013 due to higher volumes and higher average field-level prices. The increase in production volumes was primarily driven by increases in the Williston Basin due to the continued development of the properties acquired in 2012. The Company also had an additional 418.2 Mbbls of production in the second quarter of 2014 from its Permian Basin Acquisition, which closed February 25, 2014. These increases were partially offset by a decrease in the Midcontinent due to fewer well completions and divestitures of non-core properties in the third quarter of 2013. Field-level oil prices increased 3% in the second quarter of 2014, primarily due to higher oil prices in the Williston Basin, a portion of which are referenced against Brent prices, which increased in second quarter of 2014 compared to 2013.

Oil revenues increased $244.7 million, or 61%, in the first half of 2014 when compared to the first half of 2013 due to higher volumes, slightly offset by lower average field-level prices. The increase in production volumes was primarily driven by increases in the Williston Basin due to the continued development of the properties acquired in 2012. The Company also had an additional 558.2 Mbbls of production in the first half of 2014 from its Permian Basin Acquisition, which closed February 25, 2014. These increases were partially offset by a decrease in the Midcontinent due to decreased well completions and divestitures of non-core properties in the third quarter of 2013 and a decrease in the Other Northern Region due to divestitures of non-core properties in the second quarter of 2013. Field level prices remained relatively constant in the first half of 2014, with a slight decrease in the Northern Region primarily due to lower oil prices in the Williston Basin, partially offset by increased prices in the Southern Region primarily related to the Permian properties.

NGL Volumes and Prices

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Change	**2014**	2013	Change
NGL production volumes (Mbbl)						
Northern Region						
Pinedale	**854.0**	337.7	516.3	**1,568.8**	649.6	919.2
Williston Basin	**204.4**	142.9	61.5	**365.3**	255.0	110.3
Uinta Basin	**177.4**	94.7	82.7	**316.8**	172.1	144.7
Other Northern	**3.3**	20.2	(16.9)	**5.3**	30.9	(25.6)
Southern Region						
Haynesville/Cotton Valley	**11.0**	4.0	7.0	**18.8**	9.3	9.5
Permian Basin	**130.4**	—	130.4	**163.4**	—	163.4
Midcontinent	**505.5**	515.5	(10.0)	**1,015.9**	1,106.6	(90.7)
Total production	**1,886.0**	1,115.0	771.0	**3,454.3**	2,223.5	1,230.8
NGL prices (per bbl)						
Northern Region	**$ 35.55**	$ 51.21	$ (15.66)	**$ 37.44**	$ 55.37	$ (17.93)
Southern Region	**32.02**	29.99	2.03	**36.26**	31.67	4.59
Average field-level price	**$ 34.34**	$ 41.32	$ (6.98)	**$ 37.03**	$ 43.48	$ (6.45)
Commodity derivative impact	**—**	—	—	**—**	—	—
Net realized price	**$ 34.34**	$ 41.32	$ (6.98)	**$ 37.03**	$ 43.48	$ (6.45)

NGL revenues increased $18.7 million, or 41%, during the second quarter of 2014, when compared to the second quarter of 2013, due to increased production volumes partially offset by a decreased average price per barrel. Pinedale and Uinta NGL volumes increased due to ethane recovery in the second quarter of 2014 compared to ethane rejection in the second quarter of 2013, while the Williston Basin volumes grew as a result of increased development drilling. Additionally, the Permian Basin Acquisition contributed to the increased NGL production. These increases were partially offset by a decrease in the Midcontinent due to decreased well completions and divestitures of non-core properties in the third quarter of 2013. NGL prices decreased 17% during the second quarter of 2014 primarily as a result of recovering ethane from the wet gas production stream in Pinedale and Uinta during the second quarter of 2014, compared to no recovery in the second quarter of 2013. When ethane is recovered as an NGL instead of being sold as part of the gas stream, the average NGL barrel sales price decreases as the ethane price is lower than the remaining NGL components.

NGL revenues increased $31.2 million, or 32%, during the first half of 2014, when compared to the first half of 2013, due to increased production volumes partially offset by a decreased average price per barrel. Pinedale and Uinta NGL volumes increased due to partial ethane recovery in the first half of 2014 compared to ethane rejection in the first half of 2013, while the Williston Basin NGL volumes grew as a result of increased development drilling. Additionally, the Permian Basin Acquisition contributed to the increased NGL production. These increases were partially offset by a decrease in the Midcontinent due to decreased well completions and divestitures of non-core properties in the third quarter of 2013. NGL prices decreased 15% during the first half of 2014 primarily as a result of partially recovering ethane from the gas stream in Pinedale and Uinta during the first half of 2014, compared to no recovery in the first half of 2013.

QEP Energy Resale Margin

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Change	**2014**	2013	Change
Resale Margin	(in millions)					
Purchased gas, oil and NGL sales	**$ 49.8**	$ 54.5	$ (4.7)	**$ 86.9**	$ 117.3	$ (30.4)
Purchased gas, oil and NGL expense	**(50.1)**	(54.9)	4.8	**(88.1)**	(120.6)	32.5
Resale margin	**$ (0.3)**	$ (0.4)	$ 0.1	**$ (1.2)**	$ (3.3)	$ 2.1

During the second quarter of 2014, QEP Energy recorded a loss on resale margin of $0.3 million compared to a loss of $0.4 million in the second quarter of 2013 as a result of its activities to utilize pipeline transportation commitments in Louisiana. The Company has transportation commitments in excess of its current production as a result of the continued suspension of its Haynesville drilling program.

During the first half of 2014, QEP Energy recorded a loss on resale margin of $1.2 million compared to a loss of $3.3 million in the first half of 2013 as a result of its activities to utilize pipeline transportation commitments in Louisiana. The Company has transportation commitments in excess of its current production as a result of the continued suspension of its Haynesville drilling program.

QEP Energy Drilling Activity

The following table presents operated and non-operated well completions for the three and six months ended June 30, 2014:

	Operated Completions				Non-operated Completions			
	Three Months Ended June 30, 2014		Six Months Ended June 30, 2014		Three Months Ended June 30, 2014		Six Months Ended June 30, 2014	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Northern Region								
Pinedale	35	28.4	57	44.6	—	—	—	—
Williston Basin	31	24.6	45	37.5	7	0.3	27	1.6
Uinta Basin	1	1.0	1	1.0	17	—	112	0.3
Other Northern	—	—	—	—	—	—	—	—
Southern Region								
Haynesville/Cotton Valley	—	—	—	—	4	0.1	18	0.6
Permian Basin	14	12.8	19	17.4	—	—	—	—
Midcontinent	—	—	1	0.9	21	0.6	61	3.9

The following table presents operated and non-operated wells being drilled or waiting on completion at June 30, 2014:

	Operated				Non-operated			
	Being drilled		Waiting on completion		Being drilled		Waiting on completion	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Northern Region								
Pinedale	20	12.0	50	35.0	—	—	—	—
Williston Basin	19	13.3	18	15.8	41	1.7	26	2.7
Uinta Basin	2	2.0	1	1.0	—	—	—	—
Other Northern	—	—	—	—	—	—	—	—
Southern Region								
Haynesville/Cotton Valley	—	—	—	—	8	1.0	10	1.1
Permian Basin	6	5.4	6	5.2	—	—	—	—
Midcontinent	—	—	5	4.8	3	0.1	13	0.4

The term "gross" refers to all wells or acreage in which QEP has at least a partial working interest and the term "net" refers to QEP's ownership represented by that working interest. Each gross well completed in more than one producing zone is counted as a single well. QEP utilizes multi-well pad drilling where practical. Wells drilled are not brought into production until all wells on the pad are drilled and completed and the drilling rig is moved from the location. As a result, QEP had 80 gross operated wells waiting on completion as of June 30, 2014.

Operating expenses

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

	Three Months Ended June 30,			**Six Months Ended June 30,**		
	2014	2013	Change	**2014**	2013	Change
	(per Mcfe)					
Depreciation, depletion and amortization	**$ 2.77**	$ 3.06	$ (0.29)	**$ 2.89**	$ 3.06	$ (0.17)
Lease operating expense	**0.71**	0.59	0.12	**0.74**	0.56	0.18
Gas, oil and NGL transportation and other handling costs	**0.86**	0.76	0.10	**0.87**	0.74	0.13
Production taxes	**0.63**	0.48	0.15	**0.64**	0.46	0.18
Operating Expenses	**$ 4.97**	$ 4.89	$ 0.08	**$ 5.14**	$ 4.82	$ 0.32

Depreciation, depletion and amortization (DD&A). DD&A expense decreased $5.7 million, or $0.29 per Mcfe, in the second quarter of 2014 compared to the second quarter of 2013 due to expense decreases in the Midcontinent and Haynesville/Cotton Valley partially offset by an increase in the Williston Basin expense and additional expenses related to the Permian Basin Acquisition. The decrease in the Midcontinent DD&A expense was a result of the second quarter 2014 property sales (see Note 3 - Acquisitions and Divestitures). Upon entering into purchase and sale agreements during the second quarter of 2014, the divested Midcontinent properties were characterized as held for sale resulting in no further depletion on the fields. The decrease in expense at Haynesville is a result of decreased production. The increase in the Williston Basin expense relates to increased production partially offset by a reduction in the DD&A expense related to the retirement of properties sold in the Williston Basin during the second quarter of 2014 and a lower rate due to additional proved reserves added at the end of the 2013.

During the first half of 2014, DD&A expense decreased $20.4 million, or $0.17 per Mcfe, due to expense decreases in the Midcontinent and Haynesville/Cotton Valley partially offset by an increase in the Williston Basin expense and additional expenses related to the Permian Basin Acquisition. The decrease in the Midcontinent DD&A expense was a result of the second quarter 2014 property sales (see Note 3 - Acquisitions and Divestitures). Upon entering into purchase and sale agreements during the second quarter of 2014, the divested Midcontinent properties were characterized as held for sale resulting in no further depletion on the fields. The decrease in expense at Haynesville relates to decreased production. The increase in the Williston Basin expense relates to increased production partially offset by a reduction in the DD&A expense related to the retirement of properties sold in the Williston Basin during the second quarter of 2014 and a lower rate due to additional proved reserves added at the end of the 2013.

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Change	**2014**	2013	Change
			(per Mcfe)			
Northern Region	**$ 0.58**	$ 0.63	$ (0.05)	**$ 0.67**	$ 0.63	$ 0.04
Southern Region	**0.89**	0.53	0.36	**0.82**	0.47	0.35
Average lease operating expense	**0.71**	0.59	0.12	**0.74**	0.56	0.18

QEP Energy's LOE increased $13.8 million, or $0.12 per Mcfe, during the second quarter of 2014 compared to the second quarter of 2013. The Southern Region's LOE per Mcfe increase during the second quarter of 2014 was driven primarily by the Permian Basin Acquisition in the first quarter of 2014 as well as a per Mcfe increase in Haynesville/Cotton Valley properties due to declining production volume but relatively flat labor costs, fixed operating expenses due to the consistent well count and increased workover costs. The Northern Region decrease was driven primarily by a per Mcfe decrease in the Uinta Basin due to decreased workover and supply costs.

QEP Energy's LOE increased $29.2 million, or $0.18 per Mcfe, during the first half of 2014 compared to the first half of 2013. The Southern Region's LOE per Mcfe increase during the first half of 2014 was driven primarily by the Permian Basin Acquisition in the first quarter of 2014 as well as a per Mcfe increase in Haynesville/Cotton Valley properties due to declining production volume but relatively flat labor costs and other fixed operating expenses due to the consistent well count and increased workover costs. The Northern Region increase was driven primarily by a per Mcfe increase in the Williston Basin due to increased water injection and disposal costs, overhead and utility costs in the current year attributable to increased well count and higher operating costs in the area, partially offset by a decrease in the Uinta Basin.

Gas, oil and NGL transportation and other handling costs. Gas, oil and NGL transportation and other handling costs increased $12.6 million, or $0.10 per Mcfe, in the second quarter of 2014 when compared to the second quarter of 2013. The expense increase was primarily attributable to the Williston Basin related to increased production, partially offset by a decrease in gathering deficiency expenses recognized in the second quarter of 2013, as well as additional expenses incurred for the Permian Basin Acquisition and an increase in the Midcontinent's per Mcfe rate in 2014.

Gas, oil and NGL transportation and other handling costs increased $20.9 million, or $0.13 per Mcfe, in the first half of 2014 when compared to the first half of 2013. The expense increase was primarily due to an increase in the Williston Basin due to increased production and a higher per Mcfe rate, additional expenses incurred for the Permian Basin Acquisition as well as an increase in the Uinta Basin's per Mcfe rate.

Production and property taxes. In most states in which QEP Energy operates, QEP pays production taxes based on a percentage of field-level revenue, except in Louisiana, where severance taxes are volume-based. Production taxes increased $15.5 million, or $0.15 per Mcfe, during the second quarter of 2014 and $28.2 million, or $0.18 per Mcfe, during the first half of 2014, as a result of increased gas, oil and NGL revenues due to higher field-level gas prices and higher oil and NGL production.

Exploration expense. Exploration expenses decreased $0.9 million during the second quarter of 2014 and $3.8 million in the first half of 2014 compared to the equivalent 2013 periods. These decreases primarily related to lower exploration-related labor.

Impairment expense. Impairment expense was $1.5 million during the second quarter of 2014 and $3.5 million during the first half of 2014 related to unproved property impairments due to expiring leases and changes in drilling plans.

QEP FIELD SERVICES

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Change	**2014**	2013	Change
			(in millions)			
Revenues						
NGL sales	**$ 27.8**	$ 29.2	$ (1.4)	**$ 65.8**	$ 47.0	$ 18.8
Processing (fee based) revenues	**19.1**	19.4	(0.3)	**35.1**	35.8	(0.7)
Other processing fees	**1.2**	—	1.2	**9.3**	4.9	4.4
Gathering revenues	**36.4**	37.8	(1.4)	**69.0**	75.4	(6.4)
Other gathering revenues	**7.3**	13.1	(5.8)	**18.4**	23.3	(4.9)
Purchased gas, oil and NGL sales	**1.6**	3.4	(1.8)	**2.0**	8.5	(6.5)
Total revenues	**93.4**	102.9	(9.5)	**199.6**	194.9	4.7
Operating expenses						
Purchased gas, oil and NGL expense	**1.9**	3.5	(1.6)	**1.9**	8.6	(6.7)
Processing expense	**4.6**	4.1	0.5	**9.0**	8.2	0.8
Processing plant fuel and shrinkage	**9.8**	9.3	0.5	**21.1**	15.2	5.9
Gathering expense	**9.6**	9.6	—	**19.6**	19.9	(0.3)
Gas, oil and NGL transportation and other handling costs	**8.8**	5.4	3.4	**12.4**	8.2	4.2
General and administrative	**18.7**	10.9	7.8	**33.1**	20.4	12.7
Taxes other than income taxes	**2.9**	1.7	1.2	**4.7**	2.8	1.9
Depreciation, depletion and amortization	**16.8**	11.7	5.1	**33.3**	27.5	5.8
Total operating expenses	**73.1**	56.2	16.9	**135.1**	110.8	24.3
Net loss from asset sales	**(0.2)**	(0.1)	(0.1)	**(0.2)**	(0.4)	0.2
Operating income	**20.1**	46.6	(26.5)	**64.3**	83.7	(19.4)
Interest and other income	**—**	—	—	**—**	0.3	(0.3)
Income from unconsolidated affiliates	**1.1**	1.6	(0.5)	**3.3**	2.9	0.4
Interest expense	**(0.7)**	(5.3)	4.6	**(1.3)**	(9.3)	8.0
Income before income taxes	**20.5**	42.9	(22.4)	**66.3**	77.6	(11.3)
Income tax provision	**(7.1)**	(15.1)	8.0	**(21.7)**	(27.6)	5.9
Net income	**13.4**	27.8	(14.4)	**44.6**	50.0	(5.4)
Net income attributable to noncontrolling interest	**(5.0)**	(1.4)	(3.6)	**(10.8)**	(2.0)	(8.8)
Net income attributable to QEP Field Services	**$ 8.4**	$ 26.4	$ (18.0)	**$ 33.8**	$ 48.0	$ (14.2)

Gathering Margin

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Change	**2014**	2013	Change
Gathering Margin			(in millions)			
Gathering revenues	**$ 36.4**	$ 37.8	$ (1.4)	**$ 69.0**	$ 75.4	$ (6.4)
Other gathering revenues	**7.3**	13.1	(5.8)	**18.4**	23.3	(4.9)
Gathering expense	**(9.6)**	(9.6)	—	**(19.6)**	(19.9)	0.3
Gathering margin	**$ 34.1**	$ 41.3	$ (7.2)	**$ 67.8**	$ 78.8	$ (11.0)
Operating Statistics						
Gas gathering volumes (in millions of MMBtu)						
For unaffiliated customers	**49.3**	54.8	(5.5)	**101.1**	108.9	(7.8)
For affiliated customers	**53.9**	57.2	(3.3)	**99.4**	114.4	(15.0)
Total gas gathering volumes	**103.2**	112.0	(8.8)	**200.5**	223.3	(22.8)
Average gas gathering revenue (per MMBtu)	**$ 0.35**	$ 0.34	$ 0.01	**$ 0.34**	$ 0.34	$ —

During the second quarter of 2014, gathering margin declined 17% when compared to the second quarter of 2013 due to an 8% decrease in gathering system throughput and lower other gathering revenues. Gathering system throughput decreased primarily as a result of a 38% decline at QEP Field Services' Northwest Louisiana Hub primarily due to lower QEP Energy production resulting from the continued suspension of drilling in Haynesville as well as lower gathering volumes on the Uinta gathering system and QEP Midstream's Vermillion gathering system. Other gathering revenues decrease 44% due to lower condensate sales, lower deficiency revenue on QEP Midstream's Williston gathering system, and an overall decrease in compression revenue as a result of lower throughput during the second quarter of 2014 when compared to the second quarter of 2013.

During the first half of 2014, gathering margin declined 14% when compared to the first half of 2013 due to a 10% decrease in gathering system throughput and lower other gathering revenues. Gathering system throughput decreased primarily as a result of a 40% decline at QEP Field Services' Northwest Louisiana Hub primarily due to lower QEP Energy production resulting from the continued suspension of drilling in Haynesville as well as lower gathering volumes on the Uinta gathering system and QEP Midstream's Vermillion gathering system. Other gathering revenue decreased 21% due to lower condensate sales on QEP Midstream's Vermillion gathering system and an overall decrease in compression revenue as a result of lower throughput during the first half of 2014 when compared to the first half of 2013.

Processing Margin

The following table presents a summary of QEP Field Services' gas processing financial and operating results:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Change	**2014**	2013	Change
Processing Margin			(in millions)			
NGL sales	**$ 27.8**	$ 29.2	$ (1.4)	**$ 65.8**	$ 47.0	$ 18.8
Processing (fee-based) revenues	**19.1**	19.4	(0.3)	**35.1**	35.8	(0.7)
Other processing fees	**1.2**	—	1.2	**9.3**	4.9	4.4
Processing expense	**(4.6)**	(4.1)	(0.5)	**(9.0)**	(8.2)	(0.8)
Processing plant fuel and shrink expense	**(9.8)**	(9.3)	(0.5)	**(21.1)**	(15.2)	(5.9)
Gas, oil and NGL transportation and other handling costs	**(8.8)**	(5.4)	(3.4)	**(12.4)**	(8.2)	(4.2)
Processing margin	**$ 24.9**	$ 29.8	$ (4.9)	**$ 67.7**	$ 56.1	$ 11.6
Keep-whole margin[1]	**$ 9.2**	$ 14.5	$ (5.3)	**$ 32.3**	$ 23.6	$ 8.7
Operating Statistics						
NGL sales (Mbbl)	**490.6**	708.8	(218.2)	**1,091.8**	1,049.9	41.9
Average net realized NGL sales price (per bbl)[2]	**$ 56.71**	$ 41.21	$ 15.50	**$ 60.29**	$ 44.82	$ 15.47
Fee-based processing volumes (in millions of MMBtu)						
For unaffiliated customers	**40.7**	28.3	12.4	**63.9**	48.8	15.1
For affiliated customers	**21.9**	37.2	(15.3)	**53.4**	70.4	(17.0)
Total fee-based processing volumes	**62.6**	65.5	(2.9)	**117.3**	119.2	(1.9)
Average fee-based processing revenue (per MMBtu)	**$ 0.30**	$ 0.30	$ —	**$ 0.30**	$ 0.30	$ —

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

(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.

QEP Field Services provides gas processing services under fee-based and keep-whole agreements. Approximately 86% and 80% of QEP Field Services' net operating revenue was derived from fee-based gathering and processing agreements in the second quarter of 2014 and 2013, respectively. The increase in the fee-based contribution to the total margin was due to decreased keep-whole margin in the second quarter of 2014.

Under keep-whole arrangements, QEP Field Services processes natural gas, sells the resulting NGL at market prices and remits the natural gas energy equivalent value to its customers. Because the extraction of NGL from the natural gas during processing reduces the Btu content of the natural gas, QEP Field Services must acquire natural gas at market prices for return to its customers. Accordingly, under these arrangements the Company's revenues and margins increase as the price of NGL increases relative to the price of natural gas and decrease as the price of NGL decreases relative to the price of natural gas.

QEP Field Services' keep-whole margin decreased 37% during the second quarter of 2014, compared to the second quarter of 2013, due to lower NGL sales and higher transportation and shrink expense. NGL sales decreased primarily due to a 31% decrease in NGL sales volumes, partially offset by a 38% increase in price. The decrease in NGL sales volumes is primarily due to operating in ethane rejection in the second quarter of 2014 compared to partial ethane rejection in the second quarter of 2013 as well as a new processing agreement entered into in the second quarter of 2014 that includes a linefill inventory adjustment. Average net realized NGL prices increased 38% in the second quarter of 2014 due to higher propane prices and completion of the Blacks Fork fractionation and loading facility expansion, which gives QEP Field Services the ability to sell products into local and regional markets. Also contributing to the lower keep-whole margin was a 63% increase in gas, oil and NGL transportation and other handling costs and a 5% increase in processing fuel and shrink expense due to higher natural gas prices.

Fee-based processing revenues decreased slightly during the second quarter of 2014 compared to the second quarter of 2013, due to a 4% decrease in fee-based processing volumes. During the second quarter of 2014, the decrease in fee-based processing volumes is the result of a decline in gas gathering volumes during the first half of 2014. There was no change in fee-based processing rate during the second quarter of 2014.

QEP Field Services' keep-whole margin increased 37% during the first half of 2014, compared to the first half of 2013, due to a 40% increase in NGL sales partially offset by an increase in transportation and shrink expenses. NGL sales increased due to a 4% increase in NGL sales volumes and a 35% increase in the average net realized NGL sale price. The increase in NGL sales volumes is the result of the Iron Horse II cryogenic processing plant operating during the entire first half of 2014 (which started up late in the first quarter of 2013) and linefill cash-outs due to a contractual change in the first quarter of 2014. Also contributing to the higher NGL sales was an increase in the average net realized NGL sales price due to the higher propane prices and the 2013 completion of the Blacks Fork fractionation and loading facility expansion which gives QEP Field Services the ability to sell products into local and regional markets. Partially offsetting the increase in keep-whole margins was an increase in transportation and shrink expenses primarily due to higher natural gas prices.

Fee-based processing revenues decreased slightly during the first half of 2014 compared to the first half of 2013 due to a 2% decrease in fee-based processing volumes. During the first half of 2014, the decrease in fee-based processing volume is a result of the decline in gas gathering volumes during the first half of 2014. There was no change in fee-based processing rate during the first half of 2014.

QEP MARKETING AND RESOURCES

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Change	**2014**	2013	Change
			(in millions)			
Revenues						
Purchased gas, oil and NGL sales	**$ 605.6**	$ 370.1	$ 235.5	**$ 1,107.1**	$ 709.4	$ 397.7
Other	**1.4**	1.8	(0.4)	**2.9**	3.6	(0.7)
Total revenues	**607.0**	371.9	235.1	**1,110.0**	713.0	397.0
Operating expenses						
Purchased gas, oil and NGL expense	**605.4**	369.9	235.5	**1,103.3**	712.4	390.9
Gathering, processing and other	**0.5**	0.5	—	**0.9**	0.8	0.1
General and administrative	**0.5**	1.2	(0.7)	**1.7**	2.2	(0.5)
Production and property taxes	**0.1**	—	0.1	**0.2**	0.1	0.1
Depreciation, depletion and amortization	**0.6**	0.1	0.5	**0.9**	0.4	0.5
Total operating expenses	**607.1**	371.7	235.4	**1,107.0**	715.9	391.1
Operating income (loss)	**(0.1)**	0.2	(0.3)	**3.0**	(2.9)	5.9
Realized losses on derivative instruments	**(1.8)**	(1.2)	(0.6)	**(3.9)**	(0.3)	(3.6)
Unrealized gains losses on derivative instruments	**(0.9)**	5.8	(6.7)	**(1.2)**	4.5	(5.7)
Interest and other income	**56.6**	54.7	1.9	**105.4**	105.9	(0.5)
Interest expense	**(44.8)**	(42.0)	(2.8)	**(86.6)**	(83.3)	(3.3)
Income before income taxes	**9.0**	17.5	(8.5)	**16.7**	23.9	(7.2)
Income tax provision	**(2.7)**	(7.6)	4.9	**(5.6)**	(10.1)	4.5
Net income attributable to QEP Marketing	**$ 6.3**	$ 9.9	$ (3.6)	**$ 11.1**	$ 13.8	$ (2.7)

Resale Margin

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	**Change**	**2014**	2013	Change
Resale Margin			(in millions)			
Purchased gas, oil and NGL sales	**$ 605.6**	$ 370.1	$ 235.5	**$ 1,107.1**	$ 709.4	$ 397.7
Purchased gas, oil and NGL expense	**(605.4)**	(369.9)	(235.5)	**(1,103.3)**	(712.4)	(390.9)
Realized losses on derivative instruments	**(1.8)**	(1.2)	(0.6)	**(3.9)**	(0.3)	(3.6)
Resale margin gain (loss)	**$ (1.6)**	$ (1.0)	$ (0.6)	**$ (0.1)**	$ (3.3)	$ 3.2

Purchased gas, oil and NGL sales increased by $235.5 million, or 64%, during the second quarter of 2014, compared to the second quarter of 2013, due to a $253.3 million increase in resale oil and NGL sales, partially offset by a $17.8 million decrease in resale gas sales. Resale oil and NGL sales increased due to a 124% increase in the resale volume and a 3% increase in resale price. Resale gas sales decreased due to a 46% decrease in resale volumes, partially offset by a 67% increase in resale price.

Purchased gas, oil and NGL expense, which includes transportation expense, increased 64% in the second quarter of 2014, compared to the second quarter of 2013, due to a $253.0 million increase in resale oil and NGL purchases, partially offset by a $17.5 million decrease in resale gas purchases. Resale oil and NGL sales increased due to a 137% increase in resale purchase volumes, partially offset by a 2% decrease in resale purchase price. Resale gas purchased decreased due to a 19% decrease in the resale volumes, partially offset by a 6% increase in resale purchase price.

Purchased gas, oil and NGL sales increased by $397.7 million, or 56%, during the first half of 2014, compared to the first half of 2013, due to a $378.0 million increase in resale oil and NGL sales and a $19.7 million increase in resale gas sales. Resale oil and NGL sales increased due to a 102% increase in the resale volumes, partially offset by a 3% decrease in resale oil and NGL price. Resale gas sales increased due to a 56% increase in resale price, partially offset by a 32% decrease in resale volumes.

Purchased gas, oil and NGL expense, which includes transportation expense, increased 55% in the first half of 2014, compared to the first half of 2013, due to a $376.6 million increase in resale oil and NGL purchases and a $14.3 million increase in resale gas purchases. Resale oil and NGL sales increased due to a 105% increase in resale purchase volumes, partially offset by a 4% decrease in resale purchase price. Resale gas purchased increased due to a 27% increase in resale purchase price, partially offset by a 17% decrease in resale purchase volumes.

OTHER CONSOLIDATED EXPENSES AND INCOME

General and administrative expense. During the second quarter of 2014, general and administrative (G&A) expense increased $23.3 million, or 57% compared to the second quarter of 2013. The increase in G&A in 2014 was primarily due to the following: a $5.5 million increase in professional and outside services and compensation expense mainly related to the Enterprise Resource Planning (ERP) system implementation, feasibility studies and current transactions, including the QEP Field Services separation, QEP Midstream operating as a public company and QEP Midstream's Green River Processing acquisition; a $5.2 million increase in labor and benefits costs associated with an increase in the number of employees and the Company's annual compensation program; a $4.6 million increase in the mark-to-market value of the Deferred Compensation Wrap Plan and Cash Incentive Plan (CIP) due to an increase in our stock price; a $4.4 million increase related to an increase in the allowance for uncollectible accounts; and a $2.5 million increase for retention bonuses related to the QEP Field Services separation to be paid in December 2014 or whenever the separation of QEP Field Services occurs, whichever is earlier (see Note 9 – Restructuring Costs, for additional information).

During the first half of 2014, general and administrative (G&A) expense increased $33.9 million, or 39% compared to the first half of 2013. The increase in G&A in 2014 was primarily due to the following: a $10.0 million increase in professional and outside services and compensation expenses mainly related to the ERP system implementation, feasibility studies and current transactions, including the QEP Field Services separation, QEP Midstream operating as a public company, and QEP Midstream's Green River Processing acquisition; an $8.9 million increase in labor and benefits costs due to the increased number of employees and the Company's annual compensation program; a $4.8 million increase for retention bonuses related to the QEP Field Services separation to be paid in December 2014 or whenever the separation of QEP Field Services occurs, whichever is earlier (see Note 9 – Restructuring Costs, for additional information); a $3.9 million increase in the mark-to-market value of the deferred compensation wrap plan and CIP due to an increase in our stock price; and a $2.1 million increase related to an increase in the allowance for uncollectible accounts.

Net gain (loss) from asset sales. QEP recognized a loss on sale of assets of $198.6 million during the first half of 2014 compared to a gain on sale of $100.2 million in the first half of 2013. The loss on sale of assets recognized during the first half of 2014 primarily related to QEP Energy's sale of its interest in non-core oil and gas properties in the Midcontinent area and other non-core assets in the Williston Basin for total cash proceeds of $702.3 million, subject to post-closing purchase price adjustments, and a pre-tax loss on sale of $200.9 million. The gain on sale recognized during the first half of 2013 related to QEP Energy's sale of its interest in non-core oil and gas properties located in the Northern Region for total cash proceeds of $139.7 million and a pre-tax gain on sale of $102.5 million.

Realized and unrealized gains (losses) on derivative contracts. Gains and losses on derivative instruments are comprised of both realized and unrealized gains and losses on QEP's commodity derivative contracts and interest rate swaps, which are marked-to-market each quarter. During the second quarter of 2014, losses on commodity derivative instruments were $85.2 million, of which $34.1 million were realized and $51.1 million were unrealized. During the second quarter of 2013, gains on commodity derivative instruments were $110.2 million, of which $30.8 million were realized gains and $79.4 million were unrealized gains. Additionally, during the second quarter of 2014, losses from interest rate swaps were $2.8 million, of which $1.2 million were realized losses and $1.6 million were unrealized, compared to gains of $3.8 million during the second quarter of 2013, of which $0.7 million were realized losses offset by unrealized gains of $4.5 million.

During the first half of 2014, losses on commodity derivative instruments were $165.4 million, of which $68.8 million were realized and $96.6 million were unrealized. During the first half of 2013, gains on commodity derivative instruments were $75.8 million, of which $82.1 million were realized gains and $6.3 million were unrealized losses. Additionally, during the first half of 2014, losses from interest rate swaps were $3.5 million, of which $1.9 million were realized and $1.6 million were unrealized, compared to gains of $3.6 million during the first half of 2013, of which $1.3 million were realized losses offset by unrealized gains of $4.9 million.

Interest expense. Interest expense increased $4.3 million, or 10%, during the second quarter of 2014, compared to the second quarter of 2013. The increase was attributable to average debt levels in 2014 that were approximately $528.4 million, or 16%, higher than average debt levels in the second quarter of 2013. The increase in average debt levels is primarily related to additional borrowing on the credit facility and the increase in QEP's term loan to $600.0 million in the first quarter of 2014, both of which were used to fund the Permian Basin Acquisition.

Interest expense increased $7.4 million, or 9%, during the first half of 2014, compared to the first half of 2013. The increase was attributable to average debt levels in 2014 that were approximately $147.9 million, or 4%, higher than average debt levels in the first half of 2013. The increase in average debt levels is primarily related to additional borrowing on the credit facility and the increase in QEP's term loan to $600.0 million in the first quarter of 2014, both of which were used to fund the Permian Basin Acquisition.

Income taxes. Income tax benefit was $54.2 million during the second quarter of 2014 compared to an income tax provision of $104.8 million during the second quarter of 2013. The income tax rate was 38.3% during the second quarter of 2014 compared to a rate of 36.8% during the second quarter of 2013. The income tax benefit was primarily the result of a loss before income taxes for the second quarter of 2014, compared to net income before income taxes for the second quarter of 2013. The increase in income tax rate is primarily a result of changes in the state income tax rate and a valuation allowance assessed this quarter related to Oklahoma net operating loss carryforwards. The state income tax rate change and the valuation allowance were driven by changes in the Company's asset mix due to divestitures in the current quarter.

Income tax benefit was $30.8 million during the first half of 2014 compared to an income tax provision of $102.6 million during the first half of 2013. The income tax rate was 42.4% during the first half of 2014 compared to a rate of 36.8% during the first half of 2013. The income tax benefit was primarily the result of loss before income taxes for the first half of 2014, compared to net income before income taxes for the first half of 2013. The increase in income tax rate is primarily a result of changes in the state income tax rate and a valuation allowance assessed this quarter related to Oklahoma net operating loss carryforwards. The state income tax rate change and the valuation allowance were driven by changes in the Company's asset mix due to acquisitions and divestitures in the current year.

LIQUIDITY AND CAPITAL RESOURCES

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

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

	June 30, 2014	December 31, 2013
	(in millions, except %)	
Cash and cash equivalents	**$ 702.3**	$ 11.9
Amount available under the QEP credit facility [(1)]	**403.2**	1,016.2
Total liquidity	**$ 1,105.5**	$ 1,028.1
Total debt	**$ 3,910.8**	$ 2,997.5
Total common shareholders' equity	**$ 3,330.1**	$ 3,376.6
Ratio of debt to total capital [(2)]	**54%**	47%

(1) See discussion of revolving credit facility below. Availability under QEP's credit facility is reduced by outstanding letters of credit of $3.8 million as of June 30, 2014, and December 31, 2013, and does not include the $500.0 million available under QEP Midstream's credit facility.

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

QEP's Credit Facility

QEP’s unsecured revolving credit facility, which matures in August 2016, provides for loan commitments of $1.5 billion from a group of financial institutions. The credit facility provides for borrowings at short-term interest rates and contains customary covenants and restrictions. The credit facility also contains an accordion provision that would allow for the amount of the facility to be increased to $2.0 billion and a provision whereby the maturity can be extended for up to two additional one-year periods, with the agreement of the lenders. QEP’s weighted-average interest rate on borrowings from its credit facility was 2.20% during the six months ended June 30, 2014. At June 30, 2014, QEP was in compliance with the debt covenants under the credit agreement. As a result of QEP Field Services' Green River Processing divestiture, which generated total cash proceeds of approximately $230.0 million (see Note 15 - Subsequent Events), and QEP Energy's second quarter 2014 divestitures for total cash proceeds of $702.3 million (see Note 3 - Acquisitions and Divestitures), QEP's borrowings under its credit facility were reduced to $197.0 million as of July 31, 2014.

QEP Midstream's Credit Facility

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

There have been no borrowings under QEP Midstream's credit facility during the six months ended June 30, 2014, and at June 30, 2014, QEP Midstream was in compliance with the covenants under the QEP Midstream credit agreement. At July 31, 2014, QEP Midstream had $223.5 million of borrowings under its credit facility, which was used to fund the Green River Processing acquisition (see Note 15 - Subsequent Events).

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

Term Loan

QEP's $600.0 million unsecured term loan facility provides for borrowings at short-term interest rates and contains covenants, restrictions and interest rates that are substantially the same as QEP’s revolving credit facility. The term loan matures in April 2017, and the maturity date may be extended one year with the agreement of the lenders. In conjunction with the Permian Basin Acquisition, QEP borrowed the incremental $300.0 million available under the facility and increased total borrowings under the term loan to $600.0 million. There were no changes to the maturity date, pricing or covenants in the credit agreement. QEP incurred $1.1 million of debt issuance costs associated with the new term loan issuance.

During the six months ended June 30, 2014, QEP’s weighted-average interest rate on borrowings under the term loan was 2.23%. In conjunction with the term loan, QEP entered into interest rate swap contracts with a combined notional principal amount of $600.0 million which will mature in March 2017. Under the aggregated swap contracts, QEP pays 0.96% for the life of the swaps and receives one-month LIBOR. The interest rate at June 30, 2014, under the term loan is one-month LIBOR, plus 2.00% (the Applicable Margin) which, when combined with the fixed interest rate swaps, results in an effective rate of 2.96% 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

The Company’s senior notes outstanding as of June 30, 2014, totaled $2,221.8 million principal amount and are comprised of six issuances as follows:

- $176.8 million 6.05% Senior Notes due September 2016
- $134.0 million 6.80% Senior Notes due April 2018
- $136.0 million 6.80% Senior Notes due March 2020

- $625.0 million 6.875% Senior Notes due March 2021
- $500.0 million 5.375% Senior Notes due October 2022
- $650.0 million 5.25% Senior Notes due May 2023

Cash Flow from Operating Activities

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

Net cash provided by operating activities during the first half of 2014 increased $362.4 million compared to the first half of 2013, due to higher non-cash adjustments to net income and an increase in changes in operating assets and liabilities partially offset by a net loss incurred during the six months ended June 30, 2014. Non-cash adjustments to net income increased in the first half of 2014 compared to the first half of 2013 due to the loss on asset sales in the second quarter of 2014 and increased losses on derivative contracts. Changes in operating assets and liabilities provided $76.4 million of cash in the first half of 2014, mainly due to an increase of accounts payable and accrued expenses offset by an increase in accounts receivable. Changes in operating assets and liabilities used $222.1 million of cash in the first half of 2013 primarily due to a decrease in accounts payable and accrued expenses due to the $115.0 million Chieftain settlement payment in the first quarter of 2013 and an increase in accounts receivable. Net cash provided by operating activities is presented below:

	Six Months Ended June 30,		
	2014	2013	Change
	(in millions)		
Net income (loss)	$ **(41.8)**	$ 176.1	$ (217.9)
Noncash adjustments to net income	**825.7**	543.9	281.8
Changes in operating assets and liabilities	**76.4**	(222.1)	298.5
Net cash provided by operating activities	$ **860.3**	$ 497.9	$ 362.4

Cash Flow from Investing Activities

In the first half of 2014, net cash used in investing activities was $972.1 million, compared to $598.9 million in the first half of 2013. This increase in investing activities was largely due to the Permian Basin Acquisition, which closed in the first quarter of 2014 for a total purchase price of $942.1 million, subject to post-closing purchase price adjustments. A comparison of capital expenditures for the first half of 2014 and 2013 and a forecast for calendar year 2014 are presented in the table below:

	Six Months Ended June 30,			**Current Forecast Twelve Months Ended [1]**	Prior Forecast Twelve Months Ended [2]
	2014	2013	Change	**December 31, 2014**	December 31, 2014
			(in millions)		
QEP Energy	$ **1,710.5**	$ 697.1	$ 1,013.4	$ **1,775.0**	$ 1,650.0
QEP Field Services	**37.6**	30.1	7.5	**75.0**	80.0
QEP Marketing	**0.3**	0.5	(0.2)	**0.5**	0.5
QEP	**6.3**	11.9	(5.6)	**14.5**	24.5
Total accrued capital expenditures	**1,754.7**	739.6	1,015.1	**1,865.0**	1,755.0
Change in accruals and purchase adjustments	**(26.3)**	(2.8)	(23.5)	**—**	—
Total cash capital expenditures	$ **1,728.4**	$ 736.8	$ 991.6	$ **1,865.0**	$ 1,755.0

[1] Represents the mid-point of the most recent guidance and excludes approximately $942.1 million for the Permian Basin Acquisition.
[2] Forecast as reported in the March 31, 2014 Form 10-Q, filed on May 7, 2014.

During the first half of 2014, capital expenditures on a cash basis increased 135% to $1,728.4 million, compared to $736.8 million during the first half of 2013. The increase of $991.6 million in cash capital expenditures during the first half of 2014 was primarily the result of QEP Energy's increased capital expenditures related to the Permian Basin Acquisition.

In the first half of 2014, QEP Energy's capital investment, on an accrual basis, increased $1,013.4 million over the first half of 2013 to a total of $1,710.5 million. This increase was primarily due to the Permian Basin Acquisition, which closed in the first half of 2014 for a total purchase price of $942.1 million, subject to post-closing purchase price adjustments. In addition, capital expenditures increased $70.1 million in the Williston Basin, $91.2 million in the Permian Basin and $24.4 million in Pinedale due to additional drilling activity and operations in these areas. These increases were partially offset by decreases of $95.2 million in the Midcontinent due to divestitures of non-core properties in 2013, $20.2 million in the Uinta Basin due to a decreased rig count, and $4.9 million in the Haynesville/Cotton Valley area due to several operated completions in early 2013.

In the first half of 2014, compared to the first half of 2013, QEP Field Services' capital investment increased $7.5 million, on an accrual basis. Capital expenditures during the first half of 2014 primarily related to $7.6 million for expansion of the Uinta Basin Gathering system, $8.3 million for expansion of the Vermillion Processing Plant and $3.9 million of expansions related to other minor projects on various plants and gathering systems. The remaining expenditures related to maintenance capital expenditures.

At June 30, 2014, forecasted capital investments for 2014, excluding acquisitions, are expected to be approximately $1,865.0 million, comprised of $1,775.0 million for QEP Energy, $75.0 million for QEP Field Services, and $15.0 million for QEP Marketing and Resources. For the remainder of 2014, QEP intends to fund capital expenditures with cash flow from operating activities, and, if needed, borrowings under its revolving credit facility. QEP plans minimal capital expenditures for the Haynesville Shale and other dry-gas development areas and plans to increase capital expenditures for higher return projects, including oil-directed horizontal drilling in the Williston Basin and the Permian Basin, the latter of which was acquired in the first quarter of 2014. QEP Energy has allocated approximately 96% of its forecasted 2014 drilling and completion capital expenditure budget to oil and liquids-rich gas plays. QEP plans to invest a total of approximately $75.0 million in capital expenditures during 2014 (assuming no transactions) to maintain and grow its midstream business (including QEP Midstream), including an expansion of the Vermillion processing plant as well as additional gathering facilities in the Uinta Basin. The remaining QEP Field Services' capital expenditures will be related to compressor projects, new well connections and gathering line expansion. QEP plans to invest approximately $15.0 million in capital expenditures related to corporate activities, primarily the implementation of a new ERP system and building improvements. The aggregate levels of capital expenditures for 2014, and the allocation of those expenditures are dependent on a variety of factors, including drilling results, gas, oil and NGL prices, industry conditions, the extent to which properties or working interests are acquired, the availability of capital resources to fund the expenditures and changes in management’s business assessments as to where QEP’s capital investment can generate the best return. 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 half of 2014, net cash proceeds from financing activities were $802.2 million compared to $240.7 million in the first half of 2013. During the first half of 2014, QEP had net borrowings from the credit facility of $613.0 million and issued an additional $300.0 million under its term loan. These increased borrowings were offset by decreased checks outstanding in excess of cash balances of $85.2 million, distributions to noncontrolling interest of $15.2 million and $7.3 million of regular quarterly dividend payments during the six months ended June 30, 2014. During the first half of 2013, QEP had net borrowings from the credit facility of $198.5 million and an increase in checks outstanding in excess of cash balances of $55.8 million partially offset by regular quarterly dividend payments of $7.2 million.

At June 30, 2014, long-term debt consisted of $1,093.0 million outstanding under the credit facility, $600.0 million under the term loan and $2,221.8 million in senior notes (including $4.0 million of net original issue discount). The $613.0 million increase in borrowings under the credit facility and the $300.0 million increase in the term loan during the first six months of 2014 were primarily used to fund the Permian Basin Acquisition.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

QEP’s primary market risk exposures arise from changes in the market price for gas, oil and NGL, and 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, QEP Field Services, and QEP Marketing also have long-term contracts for pipeline capacity, and are obligated to pay for transportation services with no guarantee that QEP will be able to fully utilize the contractual capacity of these transportation commitments. In addition, a non-cash write-down of the Company's oil and gas properties may be required if future oil and gas commodity prices experience a sustained, significant decline. Furthermore, the Company's credit facility and term loan agreement have floating interest rates, which expose QEP to interest rate risk. To manage the Company's exposure to these risks, QEP enters into commodity derivative contracts in the form of fixed-price swaps to manage commodity price risk and interest rate swaps to manage interest rate risk.

Commodity Price Risk Management

QEP uses commodity price derivative instruments in the normal course of business to reduce the risk of adverse commodity price movements. However, these same arrangements typically limit future gains from favorable price movements. The types of commodity derivative instruments currently utilized by the Company are fixed-price swaps. The volume of commodity derivative instruments utilized by the Company may vary from year-to-year based on QEP's forecasted production. The derivative instruments 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 June 30, 2014, QEP held commodity price derivative contracts totaling 94.8 million MMBtu of gas and 13.1 million barrels of oil. At December 31, 2013, the QEP derivative contracts covered 139.4 million MMBtu of gas and 6.9 million barrels of oil.

The following table presents open 2014 derivative positions, which includes what was in effect as of June 30, 2014 (see Note 8 - Derivative Contracts, under Part 1, Item 1 of this Quarter Report on Form 10-Q for table as of June 30, 2014) and what is known to be in effect as of July 31, 2014:

QEP Energy Commodity Derivative Positions

Year	Type of Contract	Index	Total Volumes	Average Swap price per unit
			(in millions)	
Gas sales			**(MMBtu)**	
2014	SWAP	NYMEX	12.2	$ 4.22
2014	SWAP	IFNPCR	33.7	$ 4.08
2015	SWAP	NYMEX	25.6	$ 4.14
2015	SWAP	IFNPCR	11.0	$ 4.06
Oil Sales			**(Bbls)**	
2014	SWAP	NYMEX WTI	5.2	$ 93.54
2015	SWAP	NYMEX WTI	6.6	$ 89.98
2015	SWAP	BRENT ICE	0.4	104.95
2016	SWAP	NYMEX WTI	0.4	90.00

QEP Energy Oil Basis Swaps

Year	Index	Index Less Differential	Total Volumes	Weighted Average Differential
			(in millions)	
Oil basis swaps			**(Bbls)**	
2014	NYMEX WTI	ICE Brent	0.3	$ 13.78
2014	NYMEX WTI	LLS	0.3	$ 4.03
2015	NYMEX WTI	LLS	0.1	$ 4.03

QEP Marketing Commodity Derivative Positions

Year	Type of Contract	Index	Total Volumes	Average Swap price per MMBtu
			(in millions)	
Gas sales			**(MMBtu)**	
2014	SWAP	IFNPCR	2.0	$ 3.95
2015	SWAP	IFNPCR	1.2	4.22
Gas purchases			**(MMBtu)**	
2014	SWAP	IFNPCR	1.7	$ 3.83

Changes in the fair value of derivative contracts from December 31, 2013 to June 30, 2014, are presented below:

	Commodity derivative contracts
	(in millions)
Net fair value of oil and gas derivative contracts outstanding at December 31, 2013	$ (23.5)
Contracts settled	68.8
Change in oil and gas prices on futures markets	(127.3)
Contracts added	(38.2)
Net fair value of oil and gas derivative contracts outstanding at June 30, 2014	**$ (120.2)**

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

	June 30, 2014
	(in millions)
Net fair value - asset (liability)	**$ (120.2)**
Fair value if market prices of oil and gas and basis differentials decline by 10%	**40.2**
Fair value if market prices of oil and gas and basis differentials increase by 10%	**(280.5)**

Utilizing the actual derivative volumes, a 10% increase in underlying commodity prices would reduce the fair value of these instruments by $160.4 million, while a 10% decrease in underlying commodity prices would increase the fair value of these instruments by $160.4 million as of June 30, 2014. However, a gain or loss eventually would be 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 8 – Derivative Contracts under Part I, Item 1 of this Quarterly Report on 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, 2013. The Company's credit facility has a floating interest rate, which exposes QEP to interest rate risk. At June 30, 2014, the Company had $1,093.0 million outstanding under its revolving credit facility. If interest rates were to increase or decrease 10% over the six months ended June 30, 2014, at our average level of borrowing for those same periods, our interest expense would increase or decrease by $1.0 million for the six months ended June 30, 2014.

The Company's term loan has a floating interest rate, which also exposes QEP to interest rate risk. QEP uses interest rate swaps to mitigate a portion of its exposure to interest rate volatility risk associated with its $600.0 million term loan. For the $300.0 million term loan issued during 2012, QEP locked in a fixed interest rate of 1.07% in exchange for a variable interest rate indexed to the one-month LIBOR. For the $300.0 million term loan issued during 2014, QEP locked in a fixed interest rate of

0.86%. The interest rate swaps settle monthly and will mature in March 2017. At June 30, 2014, the fair value of the interest rate swaps was a derivative liability balance of $3.5 million. A 50 basis point decrease would cause the fair value of the interest rate swaps to decrease by $11.3 million while a 50 basis point increase would cause the fair value of the interest rate swaps to increase by $4.3 million.

The remaining $2,221.8 million of the Company's debt is Senior Notes with fixed interest rates; therefore it is not affected by interest rate movements. For additional information regarding the Company's debt instruments, see Note 10 – Debt under Part I, Item 1 of this Quarterly Report on 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;
- future gas, oil and NGL prices, their impact on operations and factors affecting the volatility of such prices;
- plans to drill or participate in wells;
- results from planned drilling operations and production operations;
- pro forma results for acquired properties;
- ability to pursue acquisition opportunities;
- expected restructuring costs;
- have one of the lowest cash operating cost structures;
- the Company's liquidity and sufficiency of cash flow from operations, cash-on-hand and availability under its credit facility to fund the Company's planned capital expenditures and operating expenses;
- plans to divest of non-core assets and use of proceeds from such divestitures;
- plans to focus operations on core areas and to separate the midstream business;
- impact of refinery and pipeline and other infrastructure constraints on oil prices;
- assumptions regarding equity-based compensation;
- recognition of compensation costs related to equity compensation grants;
- amount and allocation of forecasted capital expenditures and plans for funding capital expenditures and operating expenses;
- estimated accrual for loss contingencies and other items;
- impact of lower or higher commodity prices and interest rates;
- impact of global geopolitical and macroeconomic events;
- plans to enter into derivative contracts;
- the outcome of contingencies such as legal proceedings;
- expected contributions to the Company's pension plans and returns from plan assets;
- the significance of Adjusted EBITDA as a measure of cash flow and liquidity;
- potential for future asset impairments;
- factors impacting the timing and amount of share repurchases;
- enhancements from the new ERP system; and
- compliance with new internal controls framework.

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, 2013;
- changes in gas, oil and NGL prices;
- general economic conditions, including the performance of financial markets and interest rates;
- drilling results;

- shortages of oilfield equipment, services and personnel;
- lack of available pipeline capacity;
- QEP's ability to successfully integrate acquired assets or divest of non-core assets;
- the outcome of contingencies such as legal proceedings;
- QEP's success in spinning off QEP Field Services or completing a separation transaction of its midstream assets;
- permitting delays;
- operating risks such as unexpected drilling conditions;
- weather conditions;
- changes in maintenance and construction costs, including possible inflationary pressures;
- the availability and cost of debt and equity financing;
- changes in laws or regulations;
- legislation regarding climate change and other initiatives related to drilling and completion techniques, including hydraulic fracturing;
- derivative activities;
- substantial liabilities from legal proceedings and environmental claims;
- failure of internal controls and procedures;
- failure of QEP's information technology infrastructure or applications;
- elimination of federal income tax deductions for oil and gas exploration and development costs;
- future opportunities that QEP's Board of Directors may determine present greater potential value to stockholders than planned divestiture of assets;
- regulatory approvals and compliance with contractual obligations;
- actions, or inaction, by federal, state, local or tribal governments;
- fluctuations in processing margins;
- unexpected changes in costs for constructing, modifying or operating midstream facilities;
- lack of, or disruptions in, adequate and reliable transportation for QEP's products; and
- other factors, most of which are beyond the Company’s control.

QEP undertakes no obligation to publicly correct or update the forward-looking statements in this Quarterly Report on Form 10-Q, 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, the Exchange Act) as of June 30, 2014. Based on such evaluation, such officers have concluded that, as of June 30, 2014, the Company’s disclosure controls and procedures are designed and effective to ensure that information required to be disclosed 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.

The Company maintains a system of internal controls over financial reporting that is designed to provide reasonable assurance that its books and records accurately reflect transactions and that established policies and procedures are followed. During the quarter ended June 30, 2014, the Company completed the implementation of a new ERP system. The ERP system was implemented by QEP to improve standardization and automation, and not in response to a deficiency in internal control over financial reporting. The Company believes the implementation of the ERP system and related changes to internal controls will enhance its internal controls over financial reporting while providing the ability to scale its business in the future. The Company has taken the necessary steps to monitor and maintain appropriate internal control over financial reporting during this period of change and will continue to evaluate the operating effectiveness of related key controls during subsequent periods.

On May 14, 2013, the Committee of Sponsoring Organizations of the Treadway Commission (COSO) issued an updated version of its Internal Control - Integrated Framework (the 2013 Framework). Originally issued in 1992 (the 1992 Framework), the framework helps organizations design, implement and evaluate the effectiveness of internal control concepts and simplify their use and application. The 1992 Framework remains available during the transition period, which extends to December 15, 2014, after which time COSO will consider it as superseded by the 2013 Framework. As of June 30, 2014, QEP has initiated the process to ensure we are in compliance with the 2013 Framework, and we anticipate we will be in compliance by the required due date of December 15, 2014.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Information regarding legal proceedings is set forth in Note 11 - Contingencies to the Company's condensed 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, 2013. Below are material changes to such risk factors that have occurred during the three months ended June 30, 2014.

Requirements to reduce gas flaring could have an adverse effect on our operations.

Wells in the Bakken and Three Forks formations in North Dakota, where we have significant operations, produce natural gas as well as crude oil. Constraints in the current gas gathering network in certain areas have resulted in some of that natural gas being flared instead of gathered, processed and sold. The North Dakota Industrial Commission, the State's chief energy regulator, recently issued an order to reduce the volume of natural gas flared from oil wells in the Bakken and Three Forks formations. In addition, the Commission is requiring operators to develop gas capture plans that describe how much natural gas is expected to be produced, how it will be delivered to a processor and where it will be processed. Production caps or penalties will be imposed on certain wells that cannot meet the capture goals. These capture requirements, and any similar future obligations in North Dakota or our other locations, may increase our operational costs or restrict our production, which could materially and adversely affect our financial condition, results of operations and cash flows.

Crude oil from the Bakken and Three Forks formations may pose unique hazards that may have an adverse effect on our operations.

The U.S. Department of Transportation has started rulemaking to develop new requirements for shipping crude oil by rail. Any new regulations that significantly affect transportation of crude oil production could materially and adversely affect our financial condition, results of operations and cash flows.

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

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

Period	Total shares purchased [1]	Weighted-average price paid per share	Total shares purchased as part of publicly announced plans or programs	Maximum number of shares that may yet be purchased under the plans or programs
April 1, 2014 - April 30, 2014	312	$ 31.43	—	—
May 1, 2014 - May 31, 2014	—	—	—	—
June 1, 2014 - June 30, 2014	—	—	—	—

(1) All of the 312 shares purchased during the three-month period ended June 30, 2014 were acquired from employees in connection with the settlement of income tax and related benefit withholding obligations arising from vesting in restricted stock grants. These shares were not part of a publicly announced program to purchase common stock. Stock options that are net settled do not involve the acquisition of any shares.

In January 2014, QEP's Board of Directors authorized the repurchase of up to $500.0 million of the Company's outstanding shares of common stock. This authorization is effective until January 2015. The timing and amount of any QEP share repurchases will depend upon a number of factors, including general market conditions, the Company’s financial position and the estimated intrinsic value of the Company’s shares. The repurchase plan does not obligate QEP to acquire any specific number of shares and may be discontinued at any time. During the six months ended June 30, 2014, no shares were repurchased.

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	QEP Resources, Inc. Deferred Compensation Plan for Directors, Amended and Restated, effective as of August 1, 2014.
10.2	Purchase and Sale Agreement, dated May 2, 2014, between QEP Energy Company, as seller, and Cimarex Energy Co., as buyer. (Incorporated by reference to Exhibit No. 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on May 8, 2014.)
10.3	Purchase and Sale Agreement, dated May 5, 2014, between QEP Energy Company, as seller, and EnerVest Energy Institutional Fund XIII-A, L.P., EnerVest Energy Institutional Fund XIII-WIB, L.P., EnerVest Energy Institutional Fund XIII-WIC, L.P., and FourPoint Energy, LLC, as buyer, and EnerVest, Ltd. (Incorporated by reference to Exhibit No. 10.2 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on May 8, 2014.)
10.4	Purchase and Sale Agreement, dated May 7, 2014, by and among QEP Field Services Company, QEP Midstream Partners GP, LLC, and QEP Midstream Partners Operating, LLC, and QEP Midstream Partners, LP. (Incorporated by reference to Exhibit No. 10.3 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on May 8, 2014.)
31.1	Certification signed by Charles 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 Charles 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)
August 6, 2014	/s/ Charles B. Stanley
	Charles B. Stanley, Chairman, President and Chief Executive Officer
August 6, 2014	/s/ Richard J. Doleshek
	Richard J. Doleshek, Executive Vice President and Chief Financial Officer

Exhibit 10.1

QEP RESOURCES, INC.

DEFERRED COMPENSATION PLAN FOR DIRECTORS

QEP RESOURCES, INC.
DEFERRED COMPENSATION PLAN FOR DIRECTORS

ARTICLE 1
INTRODUCTION

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

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

ARTICLE 2
DEFINITIONS

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

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

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

2.3

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

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

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

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

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

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

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

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

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

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

2.14 "Effective Date" shall have the meaning set forth in Section 1.3 hereof.

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

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

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

2.18 "Phantom Stock Agreement" means an agreement entered into between the Company and a Director evidencing the grant of shares of Phantom Stock to the Director.

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

2.20 "Plan Year" means the calendar year.

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

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

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

ARTICLE 3
ELIGIBILITY; PARTICIPATION

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

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

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

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

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

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

ARTICLE 4
ELECTIONS; AMOUNTS; MODIFICATIONS

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

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

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

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

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

ARTICLE 5
ACCOUNTS; DEEMED INVESTMENTS

5.1 Accounts. The Company shall establish an Account for each Participant with at least two sub-accounts - an Equity Compensation Sub-Account and a Cash Compensation Sub-Account - along with such additional sub-accounts as it deems necessary or desirable for the proper administration of the Plan. The Equity Compensation Sub-Account shall reflect the value of Phantom Stock issued to the Participant in lieu of Restricted Stock for each Plan Year, together with any adjustments for income, gain or loss and any payments from such sub-account as provided herein. Phantom Stock shall be credited to the Participant's Equity Compensation Sub-Account and relevant sub-accounts (if any) as of the effective date set forth in the Participant's Phantom Stock Agreement. The Cash Compensation Sub-Account shall reflect all deferrals of Cash Compensation made by the Participant for each Plan Year, together with any adjustments for income, gain or loss and any payments from such sub-account as provided herein. Cash Compensation deferred by a Participant under this Plan shall be credited to the Participant's Cash Compensation Account and relevant sub-accounts (if any) as soon as administratively practicable after the amounts would have otherwise been paid to the Participant.

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

5.3 Deemed Investment of Amounts Deferred.

(a) Equity Compensation Sub-Account. The Participant's Equity Compensation Sub-Account shall hold shares of the Participant's Phantom Stock and shall be credited with earnings and dividends as set forth in the Phantom Stock Agreement(s) between the Company and the Participant. In the event the Participant forfeits shares of Phantom Stock in accordance with the terms of a Phantom Stock Agreement, the Participant's Equity Compensation Sub-Account shall be debited for the number of shares of Phantom Stock forfeited along with any earnings and dividends related to such shares.

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

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

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

ARTICLE 6
DISTRIBUTIONS

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

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

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

(i) a single lump sum;

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

(iii) in the case of an in-service distribution a single lump sum of the entire Account Balance made in one or more Plan Years, as designated by the Participant.

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

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

6.3 Calculation of Distributions.

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

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

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

ARTICLE 7
WITHDRAWALS FOR UNFORESEEABLE EMERGENCIES

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

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

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

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

ARTICLE 8
ACCOUNT STATEMENTS

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

ARTICLE 9
ADMINISTRATION

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

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

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

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

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

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

ARTICLE 10
AMENDMENT AND TERMINATION

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

ARTICLE 11
MISCELLANEOUS

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

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

11.3 No Assignment or Alienation.

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

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

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

11.5 No Creation of Rights. Nothing in this Plan shall confer upon any Participant the right to continue as a Director. The right of a Participant to receive a cash distribution shall be an unsecured claim against the general assets of the Company. Nothing contained in this Plan or its component Programs nor any action taken hereunder shall create, or be construed to create, a trust of any kind, or a fiduciary relationship between the Company and the Participants, Beneficiaries, or any other persons. All

Accounts under the Plan and its component Programs shall be maintained for bookkeeping purposes only and shall not represent a claim against specific assets of any Company.

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

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

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

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

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

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

[*Signature Page Follows*]

I hereby certify that this QEP Resources, Inc. Deferred Compensation Plan for Directors was duly amended by the Board of Directors of QEP Resources, Inc. on July 28, 2014.

Executed on this 30th day of July, 2014.

By: /s/ Richard J. Doleshek
Richard J. Doleshek
Executive Vice President and Chief Financial Officer

Exhibit 31.1

CERTIFICATION

I, Charles B. Stanley, certify that:

1. I have reviewed this Form 10-Q of QEP Resources, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

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

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

August 6, 2014

/s/ Charles B. Stanley

Charles B. Stanley
Chairman, President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Richard J. Doleshek, certify that:

1. I have reviewed this Form 10-Q of QEP Resources, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

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

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

August 6, 2014

/s/ Richard J. Doleshek

Richard J. Doleshek
Executive Vice President and Chief Financial Officer

Exhibit 32.1

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

In connection with this report of QEP Resources, Inc. (the Company) on Form 10-Q for the period ended June 30, 2014, as filed with the Securities and Exchange Commission on the date hereof (the Report), Charles B. Stanley, Chairman, President and Chief Executive Officer of the Company, and Richard J. Doleshek, Executive Vice President and Chief Financial Officer, each hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his knowledge:

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

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

QEP RESOURCES, INC.

August 6, 2014

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

August 6, 2014

/s/ Richard J. Doleshek
Richard J. Doleshek
Executive Vice President and Chief Financial Officer